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Engineering Evaluation of Control Technology for H-Coal and Exxon Donor Solvent Processes

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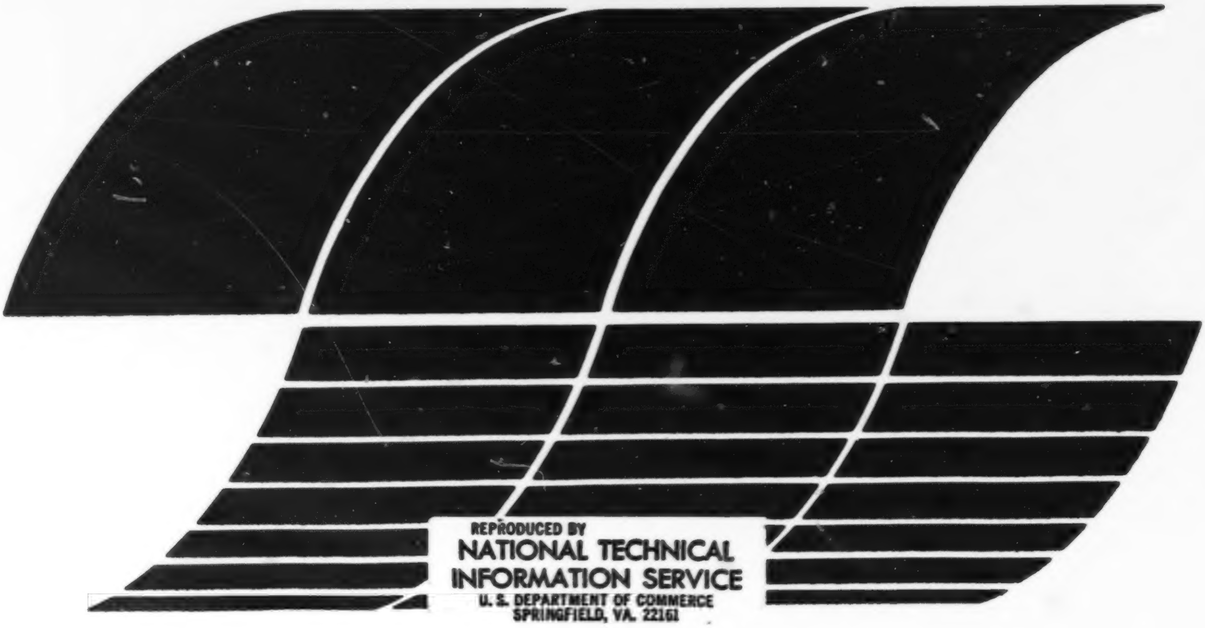

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16. ABSTRACT
The report gives results of an evaluation of the control technology of two coal liquefaction processes, H-Coal and Exxon Donor Solvent. The effluent streams were characterized and quantified for both processes and plants (pilot and conceptualized commercial). The gaseous-, liquid-, and solid-stream emissions were analyzed for their controllability, process complexity, and efficiency. Extrapolations to the larger commercial size were based partly on pilot plant data and (where such data was unavailable) engineering judgment. Several information gaps were encountered for liquid and solid effluent streams, especially as to composition. These deficiencies were pointed out and recommendations were outlined. Present control technology for the H-Coal process seems to be barely adequate: present designs are inadequate for zero discharge criteria. Control technology for the EDS process depends on being able to rely on the facilities of an adjacent refinery's controls: the scalability of present control technologies, especially in the case of the bag filter operation, is not confirmed.

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by

K. R. Sarna and D. T. O'Leary

Dynalectron Corporation/Applied Research Division
6410 Rockledge Drive
Bethesda, Maryland 20034

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EPA Project Officer: Robert A. McAllister

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
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ABSTRACT

Control technology of the two coal liquefaction processes, namely, H-Coal™ and Exxon Donor Solvent (EDS) process, has been evaluated for both pilot plants and conceptualized commercial plants. The effluent streams have been characterized and quantified for both processes and plants (pilot and commercial).

The emissions via gaseous effluents, liquid effluents and solid streams were analyzed for their controllability, process complexity and efficiency. Extrapolations to the larger commercial size were based partly on pilot plant data and engineering judgment when such data was not available.

Several gaps in information were encountered in cases of liquid and solid effluent streams,especially in their composition. These deficiencies were pointed out and recommendations were outlined.

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The data base for the preparation of this report consists primarily of information available in the the public domain (consult the list of references). Some additional information was obtained through direct contact with the managers of the coal liquefaction processes.

Section 1

INTRODUCTION

The increasing inability of the United States economy to meet its needs for petroleum based products through domestic sources has had serious repercussions on the Nation's economy and on its international political and military posture.

Thus, in informed circles, there is a realization of the need to have available alternative reliable and economical sources of energy to offset the uncertainties associated with events such as oil embargoes, and externally dictated increases in the price of petroleum and natural gas products. Fortunately, the United States is extremely rich in alternative sources of synthetic crudes,especially in recoverable coal reserves which have been estimated at 250 billion tons.

As of today, three coal liquefaction processes have been identified as having superior promise for commercial development, namely, the H-Coal^{TM} Process, the Exxon Donor Solvent (EDS), and the Solvent Refined Coal Process (SRC II). Currently,a 50 ton/day SRC II pilot plant is being operated in Takoma, Washington while pilot plants for the H-Coal^{TM} and EDS processes are being constructed in Catlettsburg, Kentucky and Baytown, Texas, respectively.

The Environmental Protection Agency (EPA), as part of its mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems, has undertaken a comprehensive fuel process assessment program. The goal of the program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. As part of this program, the EPA has contracted with Dynalectron Corporation, through its Applied Research Division, to make an engineering evaluation of control technology for two coal liquefaction processes, namely, the H-Coal^{TM} process and the Exxon Donor Solvent Process (EDS).

Most coal liquefaction processes surfacing to prominence today are all heavily involved in the generation of data on the liquefaction process itself. A large effort is being directed at catalysts, catalyst life studies, slurry properties, etc. in order to evaluate all the process parameters. On the other hand, only a limited effort is being made by the process developers toward the control technology aspects of these processes, basically because of two reasons: (1) the control technology is solely considered as an "end-of-pipe" adjunct to a process itself, and (2) the control technology is assumed to be standard and straightforward. Although both reasons may be valid, the engineering evaluation of these control technologies is warranted. It must be reiterated that the purpose of this study is to evaluate only the control technology of the converter outputs and therefore no attempt is made to comment on the processes or thermal efficiencies. The methodology of evaluation is outlined below.

The process is first divided into system operations and auxilliary processes such as coal handling, reaction and primary separations, product separations, gas treatment, water treatment and solids disposal. For each of these subsections, the flow streams as inputs and outputs are determined along with their compositions. The emissions are then characterized as to their rates, concentrations and other features such as cyclic variations and excursions.

As a second step, the control system and the technology behind it are evaluated for a) their removal efficiency, b) efficacy to this process as designed and c) scalability for commercial application.

Next, the emissions are extrapolated to a commercial plant of a suitable size, say 50,000 Bbl/day or 25,000 Tons of coal per day as feed. The control technology features for this size are then determined taking into account the extrapolatability of the pilot plant design. A comparative assessment of both technologies is then made.

A conversion table to SI units is included in the Appendix of this report.

Section 2

CONCLUSIONS AND RECOMMENDATIONS

2.1 GENERAL

A critical evaluation of the control technology of the two coal liquefaction processes (H-Coal and EDS) shows a mix of some accomplishments and some deficiencies. Most of the former are in the process category and many of the latter are in the area of environment and control technology. These deficiencies are listed below along with some recommendations.

1. Conclusion: Only end-of-pipe control technology has been attempted. However, an integrated approach may prove to be more advantageous.

   Recommendation: Studies are needed for determining that end-of-pipe approach is the only approach applicable and that an integrated approach is economically not competitive.

2. Conclusion: All coal conversion plants degrade the environment, by releasing carbon dioxide, depleting water supplies and depositing solid wastes that could be harmful. The extent of this degradation has not been assessed.

   Recommendation: An accurate assessment of the extent of environmental degradation of a coal liquefaction plant must be made with contributory breakdown of air, water and land degradation.

3. Conclusion: Any coal liquefaction plant must, by logistics, be located near a large mine or a cluster of small mines. Although coal mining does not require large quantities of water, a coal liquefaction plant does. The impact of this kind of water use and the ability of a water body near a mine cluster to support a liquefaction plant have not been quantified.

   Recommendation: The impact of irrecoverable water use must be assessed.

4. Conclusion: As a mine is depleted and finally abandoned, it can be used for disposal of solid wastes. However, the impact and long range effects of such a scheme have not been evaluated thoroughly.

Recommendation: Solid waste disposal in abandoned mines should be studied both from technical and environmental standpoints.

2.2 H-COAL PROCESS

The evaluation of the control technology of H-Coal process has led to the following conclusions. Obviously, these are based on the present state-of-the-art of the processes and technology involved. Furthermore, the pilot plant presently under construction forms the basis for many of the following conclusions.

The main thrust of the design and proposed operation of the pilot plant, is directed towards filling the process-related information gaps only. Control technology testing and verification seem to be peripheral at best.

The entire control technology of coal handling, pulverizing and feeding consists of collecting coal pile runoff (for some later treatment) and bag filters for dust control. The basis of assurance that these are sufficient has not been established. Also, the scalability of this particular technology to commercial plant size is still in doubt for particulate control via filters and also for runoff collection and transfer.

Tail gas cleanup treatment seems adequate and the technology applicable is proven. In the pilot plant it is all piped to the adjacent refinery, but the process and technology are applicable and scalable for commercial plant size.

In the pilot plant no phenol recovery is designed, but this was planned for a later date. More information on this is obviously needed because in the commercial plant this is an absolute requirement.

Neither the pilot plant, nor the conceptual commercial designs incorporate zero discharge control technology. As these plants come on stream in the early or mid 80's this zero discharge criterion becomes effective. Hence, efforts must be directed towards that goal now.

Solid waste disposal as landfill appears to be adequate. However, important information on these solids is lacking. It must be studied and determined that these solids do not contain carcinogens and mutagens and that they do not find their way into drinking waters.

2.3 EDS PROCESS

As in the case of H-Coal Process, the bulk of emphasis in the Exxon Donor Solvent Process also is directed towards process goals and the development of process-related information. The control technology in ECLP (Exxon Coal Liquefaction Plant) is almost non-existent in the sense that all effluent streams with pollutants are simply piped to the refinery next door for treatment along with its wastes or carted off as a landfill, as in the case of the solid wastes. On the commercial level, the following factors need to be considered at greater length:

(1) **The control technology of coal handling, pulverizing and feeding needs to be ensured for scalability,especially in the case of bag filter operation;**

(2) **Design of the wastewater treament plants for meeting zero discharge requirements;**

(3) **Collection, transportation and disposal of the soild wastes to comply with the regulations promulgated under the aegis of the Resource Conservation and Recovery Act of 1976.**

Section 3

STATEMENT OF THE PROBLEM AND OBJECTIVES

The increasing attention paid to coal conversion processes stands as a concern within EPA in its efforts to maintain the quality of the environment we live in. Most of the coal conversion processes, especially liquefaction, are essentially in a new technology area in which there is not enough information to assess all the environmental factors. Therefore, EPA has decided correctly and wisely to study the control technology of the coal conversion processes based on the information generated by the pilot plants. As such it is a broad assignment and requires a more precise description.

The directive describes the project as an "Engineering Evaluation of Control Technology for Converter Outputs". The evaluations are based upon the information available from existing pilot plant designs for the H-Coal and EDS processes. Several process streams have been mentioned as candidates for control technology evaluation and several pollutants have been identified for investigation. These are illustrated here in matrix form:

POLLUTANTS STREAMS	Particulates	Sulfur dioxide	Hydrocarbons	Carbonyl-sulfide	Carbon monoxide	Trace Metals	Hydrogen cyanide	Polynuclear aromatics	Hydrogen sulfide	Ammonia
Coal Feed	X		X			X				
Product Gas		X	X	X	X		X		X	X
Separator Overhead										
Vacuum Overhead										
Sour Water			X			X		X	X	X
Catalyst	X		X			X	X			
Vacuum Tower Bottoms	X		X			X		X		

The objectives of the study can be stated as:

1. to characterize the pilot plant effluent streams and the resulting emissions as to their quantity, components, and concentrations.
2. to evaluate the efficiencies of the pilot plant control technology elements.
3. to determine their applicability to the commercial size plants.
4. to identify alternate technologies other than the ones employed in the pilot plant.
5. to evaluate cost factors of the control technology as fractions of the total plant cost.
6. to identify information gaps if there are any and to make recommendations to fill these deficiencies.

Section 4

PROCESS DESCRIPTION

4.1 H-COAL

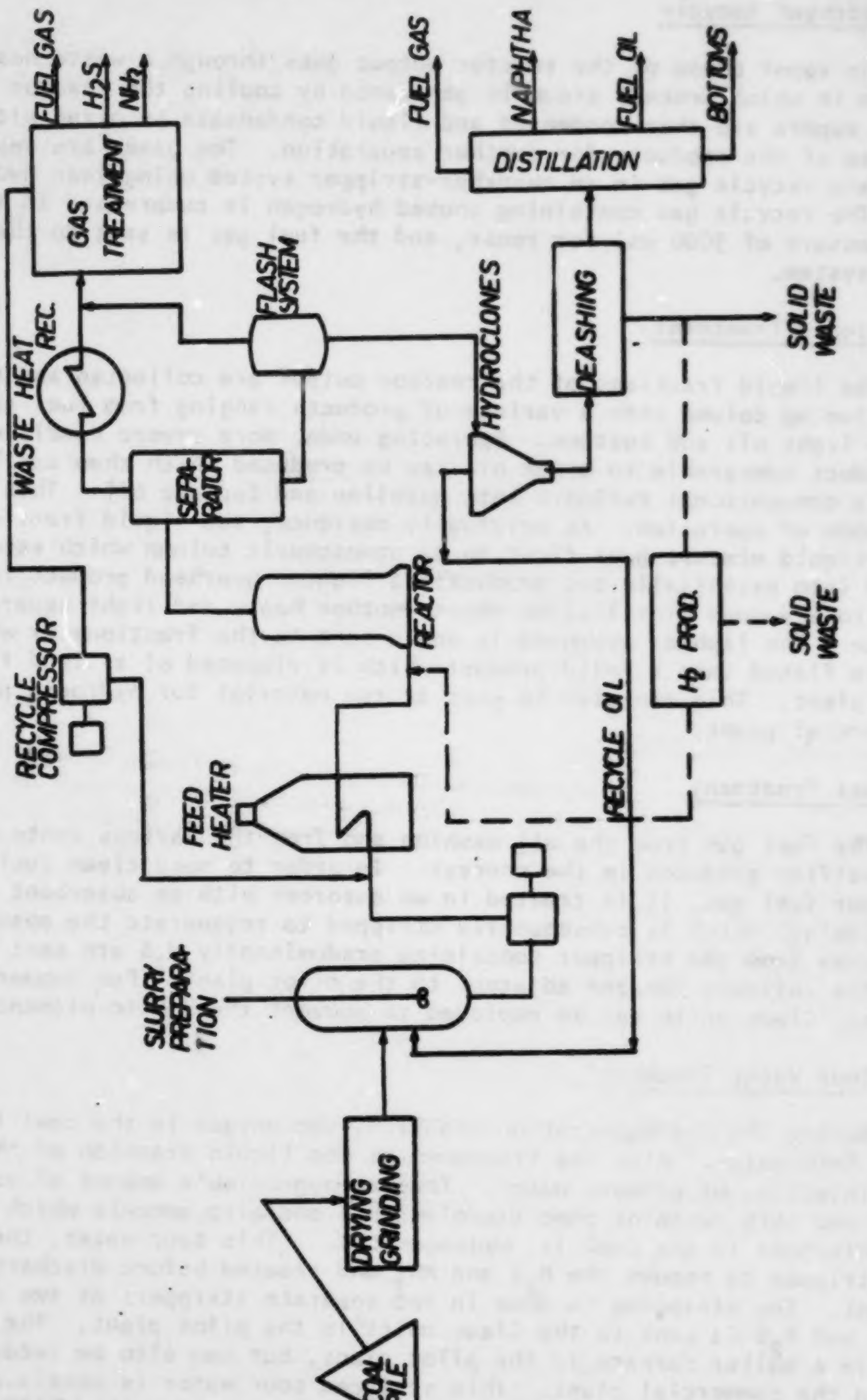
This is a process of coal conversion into predominantly liquid hydrocarbon products by means of hydrogenation of the coal in an oil slurry in the presence of a catalyst. It is a proprietary process developed by Hydrocarbon Research, Inc., (HRI) and is an innovative modification of the H-Oil process developed to hydrotreat heavy fuel oils. The H-Coal process has been studied in demonstration units and on a pilot scale by HRI under sponsorship of DOE (1). The complete design of a pilot plant having a throughput of 600 ton/day of coal, has been performed by HRI Engineering. This plant is being built at Catlettsburg, Ky. The process is shown in Figure 1 in schematic form.

4.1.1 Coal Feed Preparation

The coal is first pulverized and then dried and finely ground to about 90 percent through 200 mesh. It is then slurried with a coal derived oil (recycle oil) and the slurry is mixed with hydrogen, preheated in a fired preheater furnace to about 840°F at about 3000 psi pressure. The heated slurry is then pumped into the reactor containing the catalyst. The mixture travels up the reactor and leaves from the top. The catalyst, in the form of pellets that are larger and denser than the coal particles, however, remains in the reactor. Catalyst deactivation was found to be very rapid and so, in order to maintain a certain level of catalyst activity, part of the catalyst is periodically withdrawn and replenished with fresh catalyst.

4.1.2 Primary Separations

The reactor output consisting of unconverted coal, ash, liquid and gaseous products is first separated into a condensed phase and vapor phase. The condensed phase is then flashed in a series of drums to about 85 psi and the solid-liquid fraction is partially separated in a system of hydroclones. The hydroclone overflow is flashed to atmospheric pressure and then sent to slurry tanks for recycling. The underflow of the hydroclones is treated in an antisolvent fill in the pilot plant, but are planned to be used as a source of hydrogen production in a commercial plant.


COAL PILE
DRYING GRINDING
SLURRY PREPARATION
FEED HEATER
RECYCLE COMPRESSOR
REACTOR
SEPA-RATOR
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GAS TREATMENT
FUEL GAS
H_2S
NH_3
FLASH SYSTEM
HYDROCLONES
DEASHING
SOLID WASTE
DISTILLATION
FUEL GAS
NAPHTHA
FUEL OIL
BOTTOMS
RECYCLE OIL
H_2 PROD.
SOLID WASTE

FIG 1 SCHEMATIC OF H-COAL PROCESS (FUEL OIL MODE)

4.1.3 Hydrogen Recycle

The vapor phase of the reactor output goes through a waste heat recovery system in which process steam is generated by cooling the reactor vapors. The cooled vapors are then condensed and liquid condensate is mixed with the liquid phase of the products for further separation. The gases are separated into fuel and recycle gas in an absorber-stripper system using lean hydrocarbon oil. The recycle gas containing unused hydrogen is compressed to the reactor pressure of 3000 psi for reuse, and the fuel gas is sent to the gas treatment system.

4.1.4 Liquid Treatment

The liquid fractions of the reactor output are collected and separated in a fractioning column into a variety of products ranging from fuel gas and naphtha to light oil and bottoms. Operating under more severe conditions, a liquid product comparable to crude oil can be produced which then can be processed in a conventional refinery into gasoline and furnace oil. This is the syncrude mode of operation. As originally designed, the liquid fraction of the solid-liquid mixture goes first to an atmospheric column which separates the liquid into essentially two products; a lighter overhead product is then subjected to a vacuum distillation where another heavy and light separation takes place. The lighter overhead is again sent to the fractionator while the bottoms are flaked into a solid product which is disposed of as land fill in the pilot plant. This can also be used as raw material for hydrogen production in a commercial plant.

4.1.5 Gas Treatment

The fuel gas from the oil washing and from the various vents contains hydrogen sulfide produced in the process. In order to make clean fuel gas out of this sour fuel gas, it is treated in an absorber with an absorbent like DEA (Diethanolamine) which is subsequently stripped to regenerate the absorbent. The off gases from the stripper containing predominantly H_2S are sent to Claus units of the refinery located adjacent to the pilot plant. For commercial plants also, Claus units can be employed to convert the H_2S to elemental sulfur.

4.1.6 Sour Water Treament

During the hydrogeneration reaction, the oxygen in the coal is partially converted into water. Also the treatment of the liquid fraction of the product requires injection of process water. Thus an appreciable amount of water layer is formed and this contains some dissolved H_2S and, also, ammonia which is formed when the nitrogen in the coal is hydrogenated. This sour water, therefore, must be stripped to remove the H_2S and NH_3 and treated before discharging to the environment. The stripping is done in two separate strippers at two different pressures and H_2S is sent to the Claus units in the pilot plant. The ammonia is burned in a boiler furnace in the pilot plant, but can also be recovered as planned in the commercial plant. This stripped sour water is partly reused in the process and partly sent to the waste water treatment system where it is mixed with other waste waters for treatment and discharge into natural streams.

4.1.7 Process Diagrams

The overall material balance as input/output for the proposed operational modes and coals is shown in Figures 2 to 4. A process flow diagram of the pilot plant with material balances is shown in Figure 5.

4.2 EXXON DONOR SOLVENT PROCESS

The EDS process involves the non-catalytic liquefaction of coal in a hydrogen-donor solvent with subsequent separation of solids from liquids and catalytic hydroprocessing of the liquids to provide regenerated donor solvent and improved quality products. Preliminary process work was done on a 1 ton/day Coal Liquefaction Pilot Plant (CLPP) (2-13). In May, 1978, ground was broken in Baytown, Texas on the construction of a 250-tons/day Pilot Plant (ECLP) with a scheduled completion date of November 1979. Preliminary design work has also been completed for a 24,000-tons/day Commercial Plant. The subsequent EDS Coal Liquefaction Process Description is based primarily on the above-mentioned and ancillary sources.

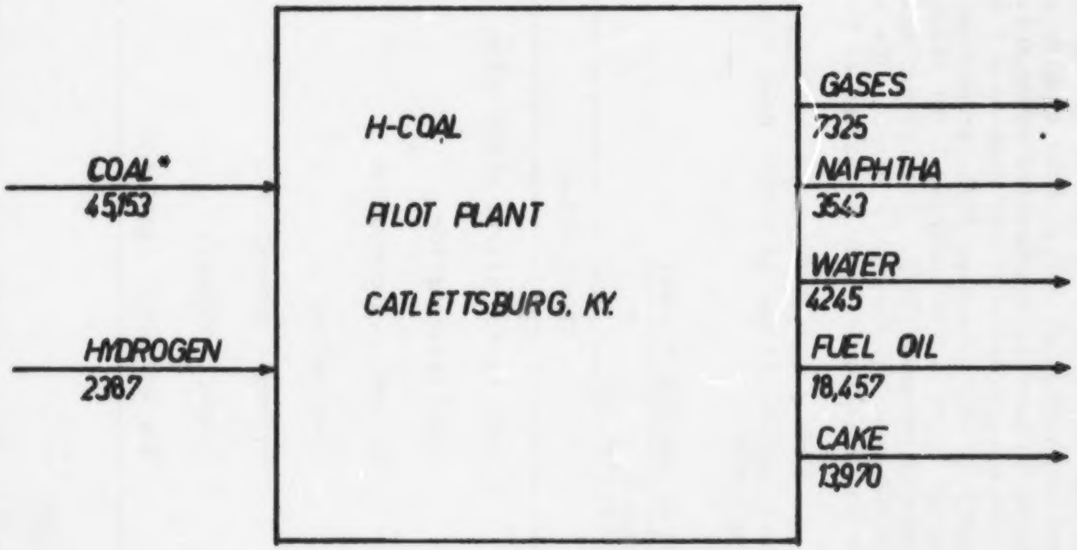
To facilitate the process description, it may be broken down into 7 system operations as per the following table:

Breakdown of the EDS Process

Operation	
Number	Description
1	Coal feed & slurry preparation
2	Coal liquefaction
3	Solvent hydrogenation
4	Flexicoking
5	Hydrogen generation
6	Product recovery
7	Gas and water treatment

4.2.1 Coal Feed & Slurry Preparation

Coal is fed via a conveyor belt from a stacker-reclaimer to a feedsurge storage silo and thence to impact mill coal crushers where the coal is mixed with the hydrogen donor recycle solvent (with a normal boiling range of 400/900°F


H-COAL
PILOT PLANT
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COAL*
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HYDROGEN
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GASES
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NAPHTHA
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WATER
4245
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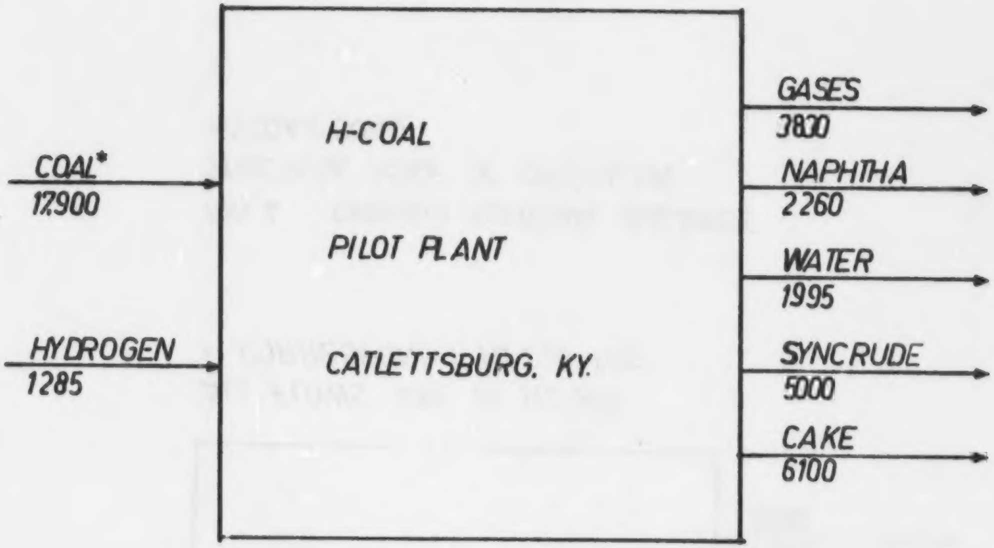
CAKE
13,970

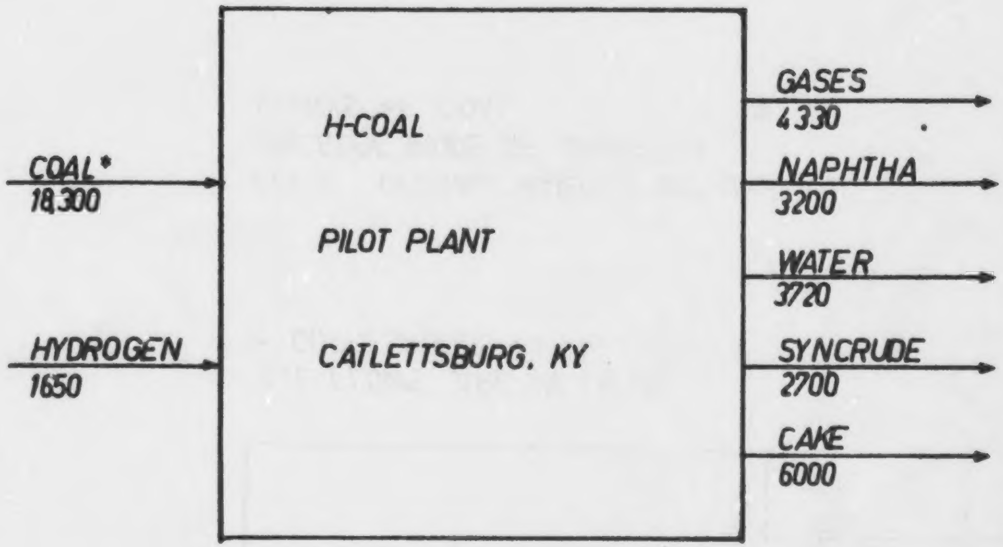
ALL FLOWS ARE IN LB/HR
* CORRESPONDS TO 541 T/D

FIG. 2 OVERALL MATERIAL BALANCE:
FUEL OIL MODE OF OPERATION
ILLINOIS #6 COAL.


COAL*
17,900
HYDROGEN
1285
H-COAL
PILOT PLANT
CATLETTSBURG. KY.
GASES
3830
NAPHTHA
2260
WATER
1995
SYNCRUDE
5000
CAKE
6100

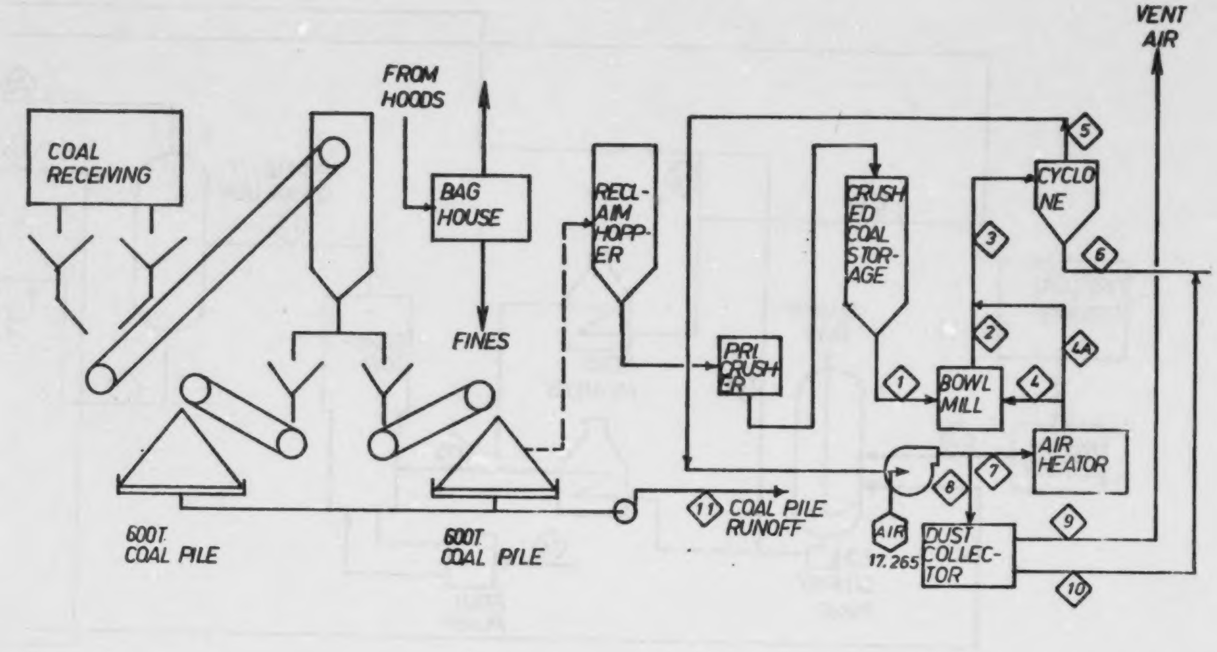
ALL FLOWS ARE IN LB/HR
* CORRESPONDS TO 215 T/D

FIG. 3 OVERALL MATERIAL BALANCE
SYNCRUDE MODE OF OPERATION
ILLINOIS #6 COAL.


COAL*
18,300
HYDROGEN
1650
H-COAL
PILOT PLANT
CATLETTSBURG, KY
GASES
4330
NAPHTHA
3200
WATER
3720
SYNCRUDE
2700
CAKE
6000

ALL FLOWS ARE IN LB/HR
* CORRESPONDS TO 220 T/D

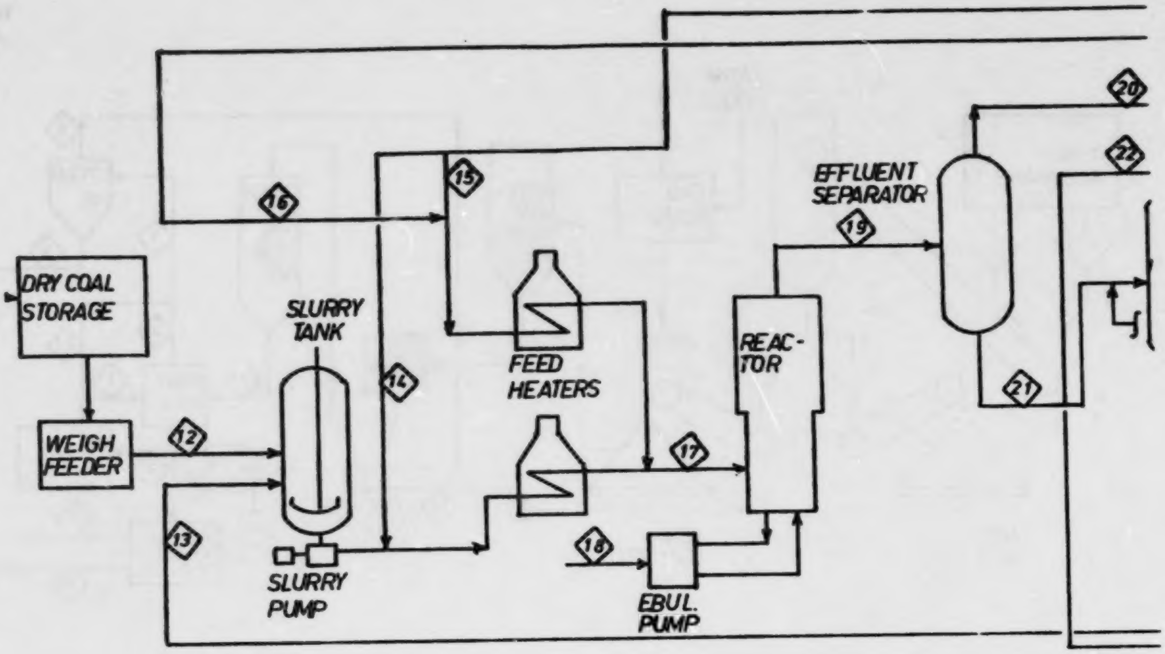
FIG. 4 OVERALL MATERIAL BALANCE
SYNCRUDE MODE OF OPERATION
WYODAK COAL.


VENT AIR
FROM HOODS
COAL RECEIVING
BAG HOUSE
RECL-AIM HOPP-ER
CRUSH ED COAL STOR-AGE
CYCLO NE
5
3
6
2
4A
FINES
PRI. CRUSH ER
1
BOWL MILL
4
AIR HEATER
7
8
AIR 17.265
9
DUST COLLEC-TOR
10
11 COAL PILE RUNOFF
600T. COAL PILE
600T. COAL PILE

STREAM / COMPONENT	① COAL FEED	② MILL EFFLUENT	③ CYCLONE FEED	④ FLUE GAS	⑤ CYCLONE DIS-CHARGE	⑥ DRY COAL	⑦ AIR TO HEATER	⑧ SLIP STREAM	⑨ VENT AIR	⑩ DRY COAL	⑪ RUN OFF
AIR		195.159	195.159	195.159	204.802			27.948			
WATER	12.043	12.043	12.043			1.200					10.000
SOLIDS	58.800	58.800	58.800		1.200	58.800		160		160	
TOTAL	70.843	266.002	266.002	195159	206.002	60.000	177.255	28108	27.948	160	10.000
TEMP. [°F]		225	225	435			225		225		
CFM (AIR)		76.000	76.000	88.630			65.650		10.351		
PCF		0.045	0.045	0.037			0.045		0.045		

1. COAL HANDLING & PREPARATION

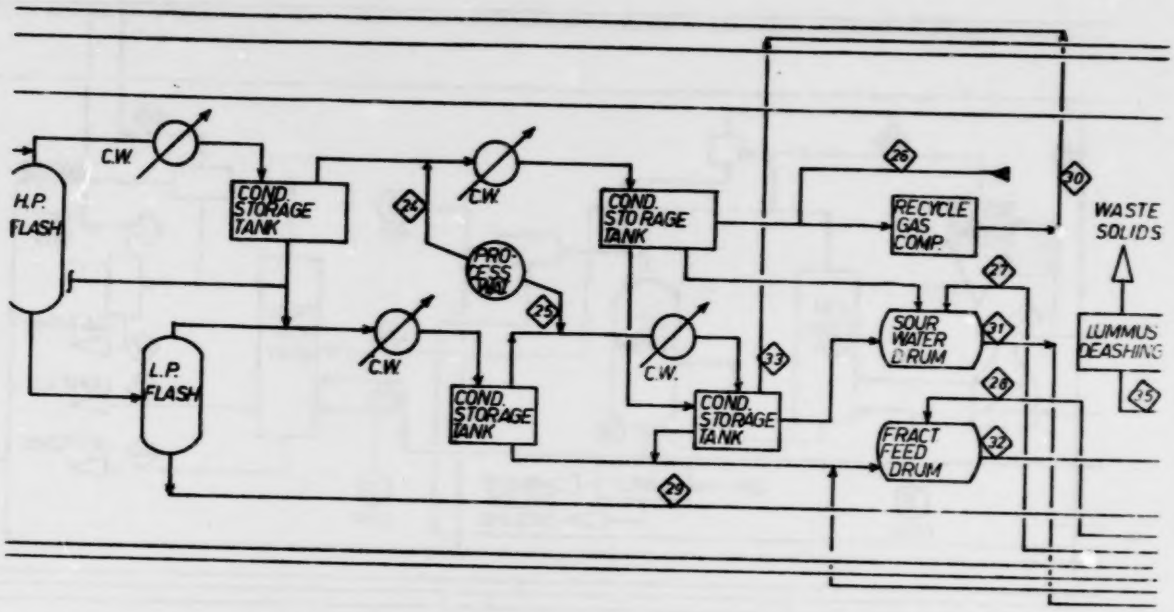
FIG. 5 PROCESS FLOW DIAGRAM OF THE PILOT PLANT


DRY COAL STORAGE
WEIGH FEEDER
SLURRY TANK
SLURRY PUMP
FEED HEATERS
REACTOR
EBUL. PUMP
EFFLUENT SEPARATOR
12
13
14
15
16
17
18
19
20
21
22

	12	13	14	15	16	17	18	19	20	21
STREAM COMPONENT	POWDER COAL	SLURRY OIL	RECYCLE GAS	RECYCLE GAS	RECYCLE GAS	REACTOR FEED	EBUL. PUMP SEAL	REACTOR EFFLUENT	EFFLUENT VAPOR	EFFLUENT LIQUID
HYDROGEN			1,667	427	2,732	4,826		3.427	2.933	495
H_2S+NH_3			195+0	50+0	345+0	590+0		2170+270	1787+220	382+50
H_2O	885		7	2		894		5.060	4.095	965
$CO+CO_2+N_2$			640	164	3.397	4,201		4.524	3.904	619
C_1-C_4 (GAS)			1.776	454	5.561	7.791		11.636	9.237	2.399
C_5+(LIQUID)		93,411	69(v)	17 (v)	79(v)	93,576	5.000	127.097	18.903(v)	108.194
SOLIDS	44.268	8.208				52.476		15.173		15.173
TOTAL [LB/HR]	45.153	101.619	4,355	1.114	12.114	164,356	5.000	169.356	41.079	128.277
TEMP [°F]/PSI		200/-	200/3015	200/3015	150/2915	747/3015	400/3015	850/3015	850/3015	850/3015
CFS/GPM		– /168	0.68/–	0.17/–	1.2/–		– /11		3.35/–	– /226
S.G./PCF		1.11/–	– /1.8	— /1.8	--/2.7		0.91/–		—/3.4	1.0/—

→ 2. SLURRYING & REACTION

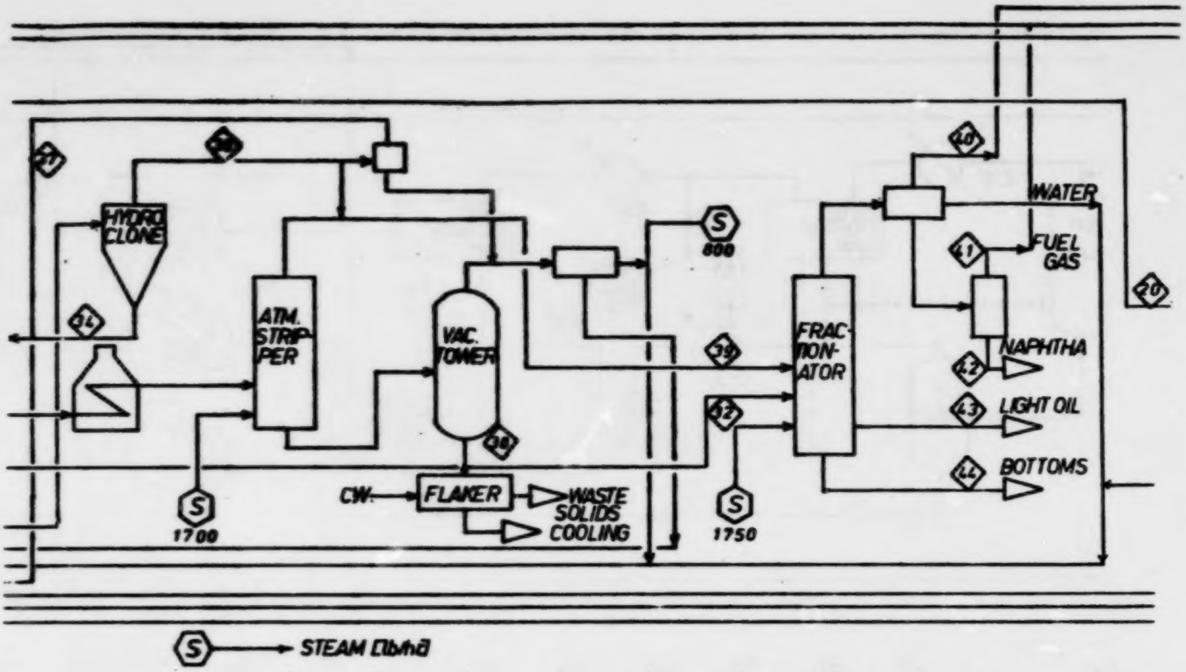
FIG. 5 (continued)


C.W.
H.P. FLASH
COND. STORAGE TANK
24
C.W.
PRO-CESS WAT.
25
C.W.
L.P. FLASH
COND. STORAGE TANK
COND. STORAGE TANK
C.W.
33
COND. STORAGE TANK
29
26
RECYCLE GAS COMP.
30
WASTE SOLIDS
27
SOUR WATER DRUM
31
LUMMUS DEASHING
28
FRACT FEED DRUM
32
35

STREAM / COMPONENT	22 LIQUID AFTER W.H.R.	23 LIQUID FROM ABSORB.	24 PROCESS WATER	25 PROCESS WATER	26 MAKE UP HYDRO-GEN	27 SOUR WAT FROM OTHERS	28 NAPHTHA AND VAC. TOWER OH	29 L.P. FLASH DRUM BOTTOM	30 RECYCLE PLUS MAKE UP	31 SOUR WAT FOR STRIPPING	32 FRACTION-ATOR FEED	33 FUEL GAS OUT
HDROGEN	49	8			1.667			3	2.094			120
$H_2S + NH_3$	84+9	97+0				382+212		13+1	245+0	485+269	9+0	186
H_2O	174		2,532	1,304	9	22,432		26	9	27.371	2	
$CO+CO_2+N_2$	75	23			271			9	804		1	171
C_1 -C_4 (GAS)	333	354			439			69	2,230		64	1,101
C_5+(LIQUID)	15.302	3.301					17,792	104,236	88(v)		39,949	395
SOLIDS								15.173				
TOTAL [LB/HR]	16.026	3.783	2.532	1,304	2.387	23,026	17,792	119.530	5.470	28.125	40.025	1,973
TEMP. [°F]/PSI	500/2965		100/1200	100/ 75	100/1600	120/—	285/ —	731/85	200/3015	120/15	285/25	125/-
CFS/GPM	— /35		—/5.0	— /2.6	1.0/ —	—/46	—/31	—/184	0.9/—	—/56	—/82	
S.G./PCF	0.9/—		1.0/—	1.0/—	—/0.7	1.0/—	1.0/—	1.13/—	— /1.8	1.0/ —	0.97/—	

3. PRIMARY SEPARATIONS

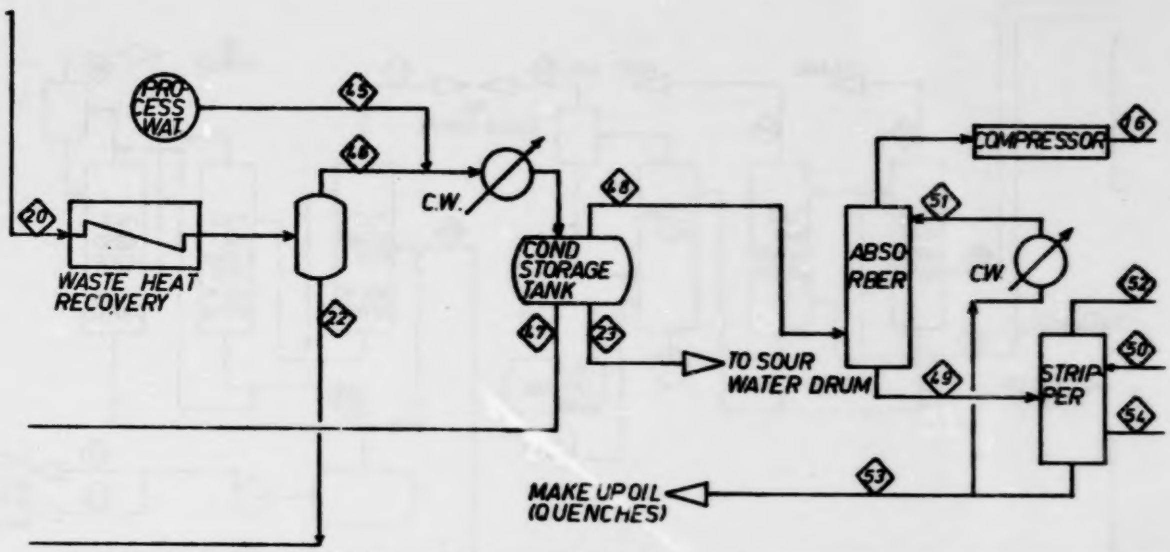
FIG. 5 (continued)


HYDRO CLONE
ATM. STRIPPER
VAC. TOWER
FLAKER
CW.
WASTE SOLIDS
COOLING
S 1700
S 800
S 1750
FRAC-TION-ATOR
WATER
FUEL GAS
NAPHTHA
LIGHT OIL
BOTTOMS
34
38
39
40
41
42
43
44
20
S → STEAM [lb/hr]

STREAM / COMPONENT	34 HYDRO-CLONE UNDR FLO	35 DEASHED STRIPPER FEED	36 HYDRO-CLONE OVERFLOW	37 RECYCLE OIL FOR SLURRY	38 VACUUM TOWER BOTTOMS	39 FRACTION ATOR FEED	40 VENT	41 FUEL GAS	42 NAPHTHA (PRODUCT)	43 LIGHT OIL	44 FRACTION ATOR BOTTOMS
HYDROGEN	1	1	2			3	3				
H_2S+NH_3	4+0	3+0	9+1			11+1	12+0	6+0			
H_2O	8	7	19			1,724					
$CO+CO_2+N_2$	3	2	6			8	8	1			
C_1-C_4 (GAS)	20	18	49			62	75	51			
C_5+(LIQUID)	29.852	37.552	74.735	56.792	15.337	23.733	61		3.543	19.341	40.735
SOLIDS	6.965		8.208	8.208							
TOTAL [LB/HR]	36.853	37.584	82.670	65.000	15.337	25.541	160	58	3.543	19.341	40.735
TEMP. [°F]/PSI	731/85	731/85	731/85	695/10	606/2.4	682/30	120/18	100/50	100/50	400/50	500/50
CFS/GPM	-/52	-/70	-/131	-/95	-/24	25/-	0.5/-	0.04/-	-/8.5	-/42	-/80
SG./PCF	1.13/-	1.06/-	1.31/-	1.19/-	1.26/-	-/0.28	-/0.08	-/0.4	0.8/-	0.9/-	1.01/-

4. PRODUCT SEPARATIONS

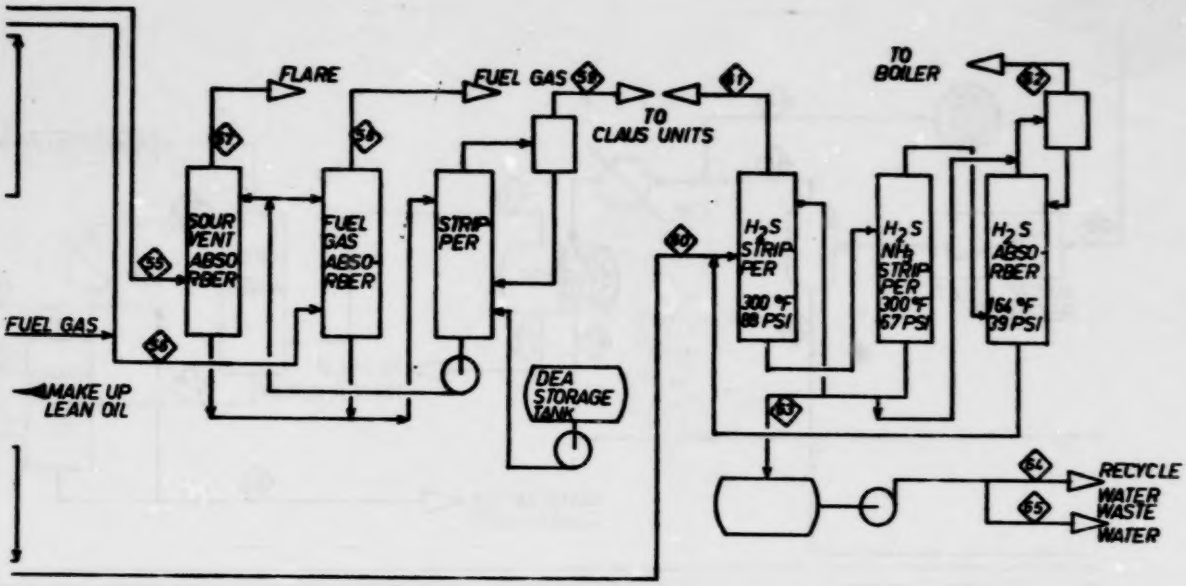
FIG. 5 (continued)


PRO-CESS WAT.
45
46
C.W.
48
COND STORAGE TANK
20
WASTE HEAT RECOVERY
22
47
23
TO SOUR WATER DRUM
COMPRESSOR
16
51
ABSORBER
C.W.
52
50
STRIPPER
49
54
53
MAKE UP OIL (QUENCHES)

STREAM / COMPONENT	45	46	47	48	49	50	51	52	53	54
	PROCESS WATER	REACTOR EFFL. VAPOR	WATER LAYER OF COND.	VAPOR TO ABSORBER	RICH OIL	MAKEUP LEAN OIL (IN)	LEAN OIL	FUEL GAS	MAKEUP OIL (QUENCH)	MAKEUP RICH OIL (OUT)
HYDROGEN		2,884		2.877	146		1	145		
H_2S+NH_3		1703+211	380+211	1.226	1.275		394	880		
H_2O	14.185	3921	18.106							
$CO+CO_2+N_2$		3,829		3.806	447		37	409		
C_1-C_4 (GAS)		8,904		8,551	4,603		1,613	2,985		
C_5+ (LIQUID)		3.598(V)		298	83,385	263	83.166	210		280
SOLIDS										
TOTAL [LB/HR]	14.185	25.050	18.697	16.758	89.856	263	85.210	4.628	ZERO IN ST. STATE	280
TEMP. [°F] /PSI	100/2965	500/2965	130/2915	130/2915	125/2915		110/2915	113/ 65		
CFS/GPM	-/28	2.3/ -	-/38	1.3/ -	-/218		-/192	6.2/ -		
S.G./PCF	1.0/ -	-/3.0	1.0/ -	-/3.5	0.8/ -		0.8/ -	-/0.2		

5. ABSORPTION SYSTEM

FIG. 5 (continued)


FLARE
FUEL GAS
59
TO CLAUS UNITS
61
TO BOILER
62
57
58
SOUR VENT ABSORBER
FUEL GAS ABSORBER
STRIPPER
H2S STRIPPER 300°F 88 PSI
H2S NH3 STRIPPER 300°F 67 PSI
H2S ABSORBER 164°F 39 PSI
55
FUEL GAS
56
MAKE UP LEAN OIL
DEA STORAGE TANK
60
63
64
RECYCLE WATER
65
WASTE WATER

	55	56	57	58	59	60	61	62	63	64
STREAM / COMPONENT	SOUR VENT GAS	SOUR FUEL GAS	H_2S STRIPPED VENT GAS	CLEAN FUEL GAS	H_2S RICH GAS TO CLAUS	SOUR WATER FLOW	H_2S TO CLAUS UNIT	NH_3 TO FURNACE	RE-CLAIMED WATER	PROCESS WATER FOR REUSE
HYDROGEN	4	289	4	289						
H_2S	44	1,381			1,425	483	483			
NH_3						269		269		
H_2O					18	27.324	13	17	27,294	
HYDROCARB.	504	4,654	504	4.654						
INERTS	10	433			443					
TOTAL	562	6.757	508	4,943	1.886	28.076	496	286	27.294	

6. DESULFURIZATION & DENITRIFICATION

FIG. 5 (continued)

and a molecular structure such as Tetralin) under ambient conditions of 1-3 psig and 275°F and a solvent to coal ratio within the range 1.1 to 2.6. Adequate residence time is provided in the dryers to dry the slurry to less than 4 wt. percent moisture on a dry coal feed basis.

4.2.2 Coal Liquefaction

Coal liquefaction implies a radical upgrading in the H/C ratio and is achieved by pumping the dried coal slurry to reaction pressure, mixing it with hydrogen treat gas and heating the resultant mixture in the liquefaction slurry/treat gas furnace. The mixture is then fed to the liquefaction non-catalytic tubular reactors which operate at 840°F and 2000 psig, where the coal liquefaction and hydrogenation takes place in the presence of molecular hydrogen and the hydrogen donor solvent. The reactor output stream is a mixture of gaseous, liquid and solid products.

The reactor products are separated into vapor and slurry streams in the liquefaction reactor separator. The vapor stream is cooled to 110°F to recover condensible hydrocarbons, water and ammonia; hydrogen sulfide and carbon dioxide are removed via water washing and scrubbing with diethanolamine. The resulting gas stream consists mainly of hydrogen and is purged to control the methane impurity level. Makeup hydrogen is then added and the treat gas is compressed for recycle to the liquefaction, three phase reactor.

The liquid/solids stream and the condensate recovered from the gas stream are fed to atmospheric and vacuum distillation towers where they are separated into a number of cuts. The products include naphtha, low sulfur fuel oil (LSFO) product, a spent solvent stream, and the vacuum bottoms slurry.

4.2.3 Solvent Hydrogenation

The purpose of the hydrogenation section is to regenerate catalytically the depleted solvent from the liquefaction reaction and to separate the reaction byproducts (gas and naphtha) from the solvent before it is recycled to the slurry drier in the liquefaction section.

A series of fixed bed reactors are used with a nickelmolybdate catalyst. The operating pressure is 1600 psig while the operating temperature is proprietary information. Weight hourly space velocities range from 0.5 to 2.0.

Effluent from the solvent hydrogenation reaction is cooled and separated into a hydrogen rich gas and a hydrotreated liquid stream. The gas is scrubbed to recover ammonia and hydrogen sulfide, a purge is taken to control the methane level, and the remaining gas, along with fresh make-up hydrogen, is recycled to the solvent hydrogenation reactor. The purge gas is sent to the liquefaction section for use as treat gas. Naphtha and a gas oil product is recovered from the hydrotreated liquid in a solvent fractionator and the solvent is recycled to the slurry dryers.

4.2.4 Flexicoking

The two-fold purpose of the flexi-coker section is to convert vacuum tower bottoms from the liquefaction section into additional liquid gas products and to supply low-Btu gas (LBG) for the rest of the plant.

The bottoms are fed to the reactor vessel where they are pyrolized to form lighter boiling overhead materials and coke. These overhead materials are cooled and scrubbed in the reactor scrubber section where a solids-laden heavy recycle stream is condensed, withdrawn and recycled to the reactor. The scrubber overhead is sent to the coker fractionator which separates the small amount of coker naphtha from the heavy low-sulfur fuel oil and wash oil streams. The coker gas, after recontacting, is treated for acid gas and nitrogen removal and then sent on as steam-reformer feed.

The reactor coke is passed to a separate vessel where it is gasified with steam and air to form low-Btu gas. After waste heat recovery, this gas is treated for removal of particulates and hydrogen sulfide. The resulting fuel gas serves to meet practically all the fuel requirements of the liquefaction plant.

4.2.5 Hydrogen Generation

Make-up hydrogen is primarily generated (seventy-seven percent) through steam reforming of a methane-ethane mixture gas emanating from the flexicoker section. The remaining twenty-three percent is provided by cryogenic purification of purge gas.

Hydrogen is then compressed to the required pressures by 3 stages of reciprocating compressors. In the first stage hydrogen is received from the reformer plants and compressed to 635 psig. The output hydrogen from this stage is combined with hydrogen from cryogenic recovery and compressed to 1740 psig (for solvent hydrogenation) in the second stage, and to 1845 psig in the third stage (for coal liquefaction).

4.2.6 Product Upgrading

The products that are upgraded in this section are low-sulfur fuel oil (LSFO) and process naptha. The LSFO meets specifications of 0.5 wt percent sulfur and a flash point specification of 160°F. A conventional light ends system is used to separate and treat the process naphtha into an ethane fraction (which is sent to steam reforming as feed), liquid C_3 and C_4 LPG fractions and a stablized C_5/400 Naphtha.

4.2.7 Gas and Waste Water Treatment

Sour water from the various process sections is combined and fed to a sour water stripping tower. Hydrogen sulfide and carbon dioxide are stripped from the sour water and sent to a Claus sulfur plant with an ancillary tail gas cleanup unit where 99.9 percent of the sulfur plant feed sulfur is recovered and emissions are reduced to about 100 ppmw SO_2. The stripped water from the sour water treating is combined with the slurry dryer water and sent to a phenol solvent extraction plant, where crude phenols are recovered. The effluent is treated in a train consisting of dissolved air flotation, biological oxidation, filtration and activated carbon. Some of the treated effluent is used as cooling tower makeup, with the remainder being discharged.

Rich DEA from on site gas treating is fed to a DEA regeneration plant where hydrogen sulfide and carbon dioxide are stripped and combined with the like gases emanating from the sour water stripping and fed to the Claus sulfur plant.

4.2.8 Historical Development of the EDS Process

The EDS process bears similarity to the Pott-Broche process that was developed in Germany prior to World War II. Exxon's effort has been underway since 1966 and has reached the stage where the construction of a 250-tons/day pilot plant is under way. The pilot plant construction costs are budgeted at $240 million with 50 percent of the financing coming from the U.S. Department of Energy and 50 percent from industry. A preliminary cost estimate for the construction of a commercial EDS process coal liquefaction plant is $1.4 billion (4).

Figure 6 is a schematic of the EDS process. Figure 7 gives the overall mass balance data for the pilot plant (known as the Exxon Coal Liquefaction Plant (ECLP) process).

The ECLP process differs from the EDS process in the following respects:

i) There is no flexicoker stage, thus there is no autogenous source of low Btu gas (LBG). The ECLP produces 1,340 lbs/hr of fuel gas of unspecified heat content (see figure 6). Supplementary fuel gas needs are met through the purchase of natural gas from local utility companies.

ii) Likewise there is no possibility of generating hydrogen through the steam reforming of the methane/ethane gas that would be produced in the flexicoker section. Some of the hydrogen process needs are met through the cryogenic purification of purge gas; however, most of the process hydrogen is supplied by the adjoining Baytown Refinery.

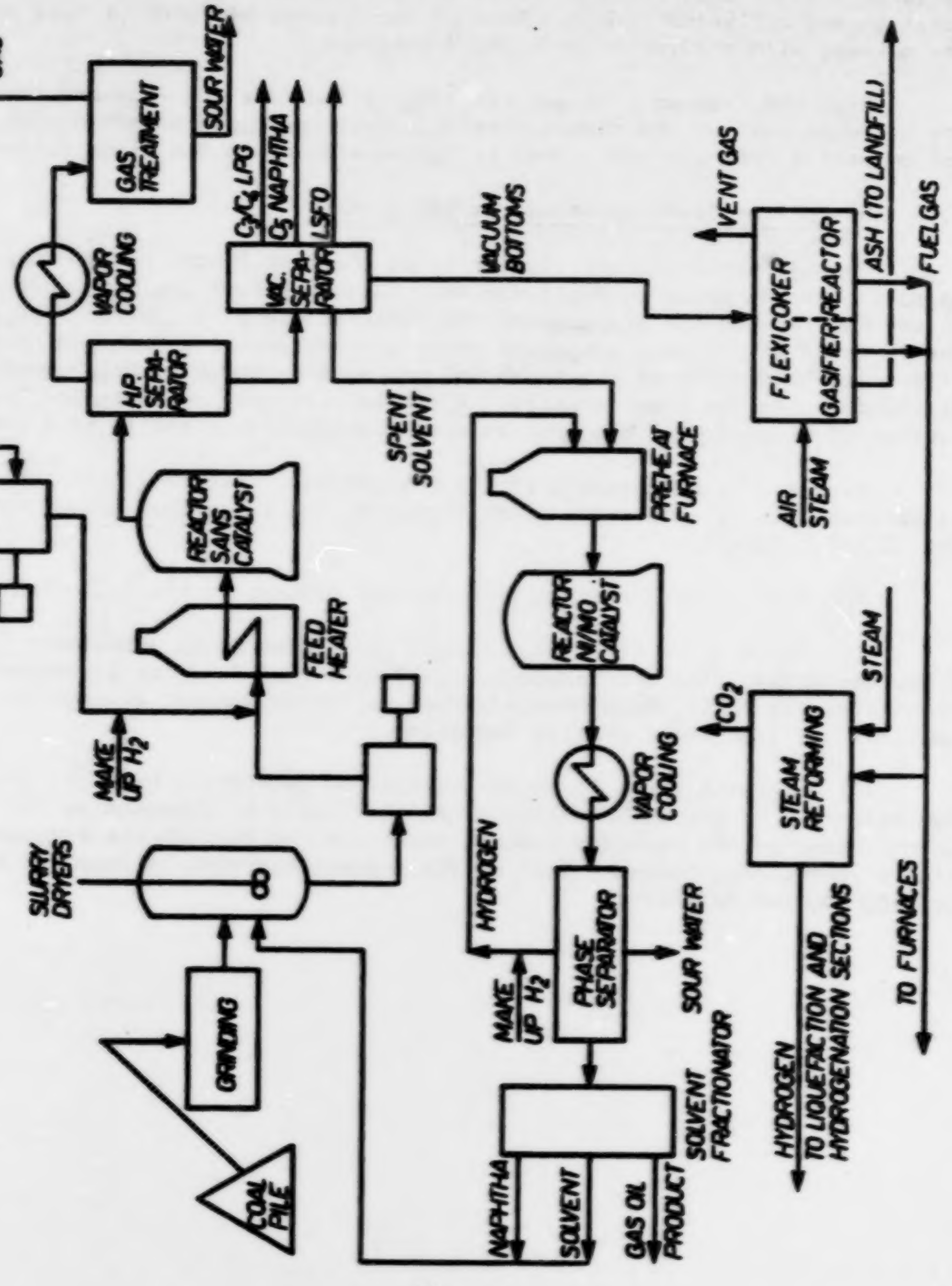
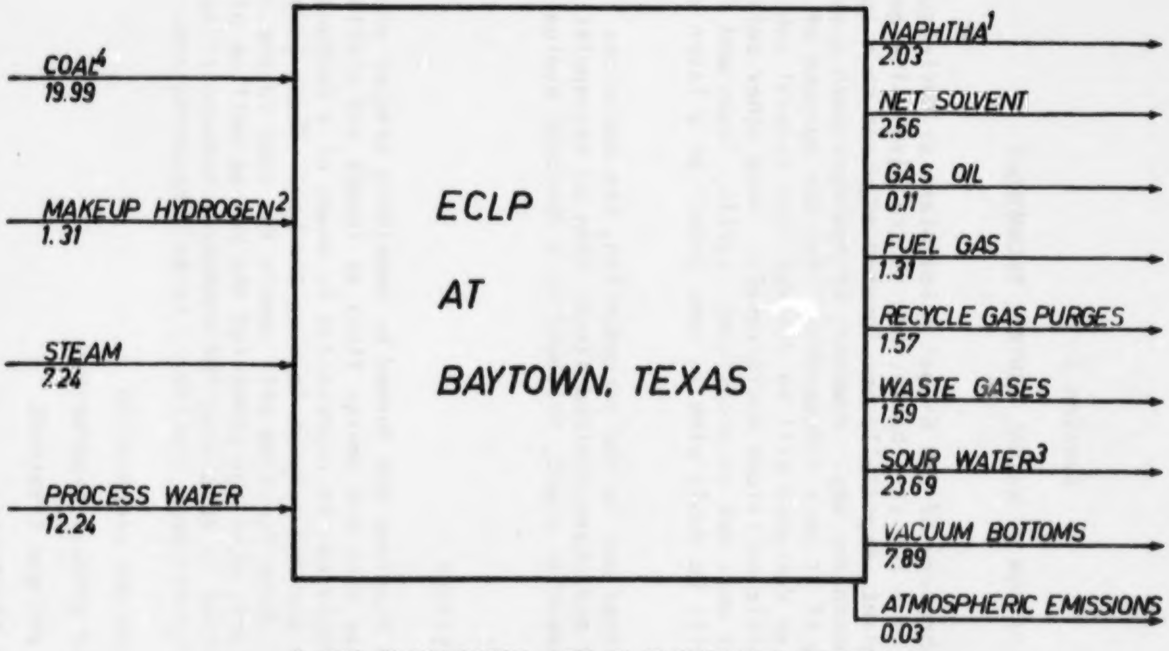

COAL PILE
GRINDING
SLURRY DRYERS
MAKE UP H_2
FEED HEATER
REACTOR SANS CATALYST
HYDROGEN
H.P. SEPARATOR
VAPOR COOLING
GAS TREATMENT
FUEL GAS
SOUR WATER
VAC. SEPARATOR
C_1-C_4 LPG
C_5 NAPHTHA
LSFO
VACUUM BOTTOMS
SPENT SOLVENT
PREHEAT FURNACE
REACTOR NI/MO CATALYST
VAPOR COOLING
HYDROGEN
MAKE UP H_2
PHASE SEPARATOR
SOUR WATER
SOLVENT FRACTIONATOR
NAPHTHA
SOLVENT
GAS OIL PRODUCT
FLEXICOKER
GASIFIER
REACTOR
VENT GAS
ASH (TO LANDFILL)
FUEL GAS
AIR
STEAM
STEAM
CO_2
STEAM REFORMING
HYDROGEN TO LIQUEFACTION AND HYDROGENATION SECTIONS
TO FURNACES

FIG.6 SCHEMATIC OF THE EDS PROCESS


COAL[4]
19.99
MAKEUP HYDROGEN[2]
1.31
STEAM
2.24
PROCESS WATER
12.24
ECLP
AT
BAYTOWN, TEXAS
NAPHTHA[1]
2.03
NET SOLVENT
2.56
GAS OIL
0.11
FUEL GAS
1.31
RECYCLE GAS PURGES
1.57
WASTE GASES
1.59
SOUR WATER[3]
23.69
VACUUM BOTTOMS
7.89
ATMOSPHERIC EMISSIONS
0.03

1. ALL FLOW RATES ARE IN THOUSANDS OF LBS/HR.
2. 95% HYDROGEN, 5% METHANE
3. INCLUDES EQUILIBRIUM AMOUNTS OF HYDROGEN SULFIDE, AMMONIA, AND CARBON DIOXIDE
4. EQUIVALENT TO 239.5 ST/SD

FIG. 7 HOURLY MATERIAL BALANCE FOR THE ECLP
ILLINOIS #6 COAL

Section 5

EVALUATION OF H-COAL CONTROL TECHNOLOGY

The control technology of the H-Coal pilot plant at Catlettsburg, Kentucky is essentially designed on a two step basis; one at the plant site and the other off-site. For a pilot plant, especially one located adjacent to a large oil refinery, this is the most convenient way. However, to evaluate such a system, the process must be analyzed as if it were independent. For the purpose of these evaluations, the pilot plant as designed will be divided into several sub-sections, from which the most possible emissions would result. Some other emissions are also expected as in-plant ones due to occasional spills, leaks and from transfer operations. These will be dealt with in some detail at a later stage under Assessment.

As has been pointed out in the Introduction, the emissions from the pilot plant will be quantified and characterized first; then an extrapolation is made of the emissions from a commercial plant, followed by a thorough evaluation of the consequences.

5.1 PILOT PLANT EMISSIONS

Process Systems Diagrams are formed by combining several process steps to form a system which has mass and energy flows as inputs and similar streams as outputs. Thus the system can be represented by means of a rectangular box with inputs entering the box and outputs leaving the box. These boxes can also be considered as modules whose function will remain the same in the commercial plant as in the pilot plant; only the sizes (of the box as well as of the streams) vary. This has an advantage in assessing the economics because it is then only a matter of scaling up. The systems, therefore, to be considered are:

1. Coal handling and preparation
2. Reaction and primary separations
3. Sour water and gas treatment
4. Waste water treatment
5. Waste solids treatment
6. Catalyst handling

We shall formulate the process system and represent the streams for these groups of process steps in the following sections.

5.1.1 Coal Handling & Preparation

5.1.1.1 Process Description: The coal is received either in railroad cars (60-100 tons capacity) or in rear dump trucks (30-50 tons capacity). The receiving station consists essentially of rows of hoppers into which the coal is unloaded. From these hoppers the coal is fed to a conveyor belt which discharges into a chute. The chute discharges either of two conveyor belts which dump the coal into two piles of approximately 600 tons of capacity.

The dust control system consists of hoods connected to air ducts leading to a dust collector of the baghouse type. The total air handled by the hopper dust collector is about 84,500 SCFM and the final discharge is into the atmosphere. Unless 100 percent collector efficiency is assured, this will constitute a point source of particulate emission.

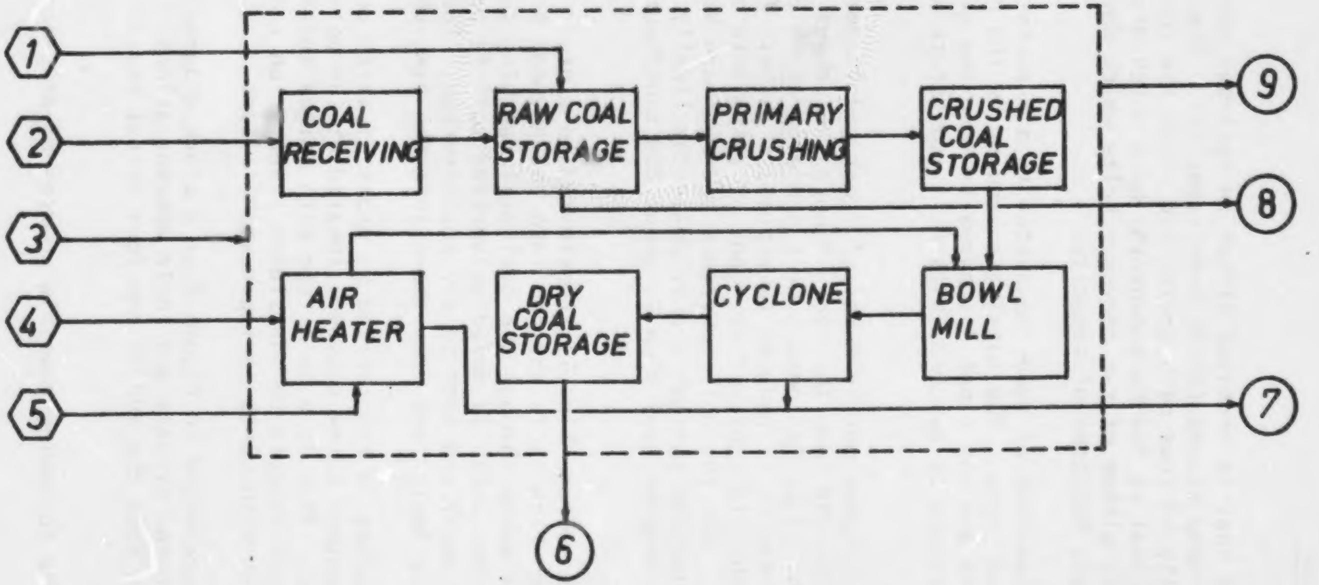
The coal from the piles is taken out by means of front end loaders (about 4 cu. yards per lift) and charged into the reclaim hopper of about 25 tons holding capacity. From this hopper it is fed onto a belt conveyor which discharges the coal into a primary crusher where it is reduced to about 3/4" size. The crushed coal from the primary crusher is conveyed by means of belts into crushed coal storage bins (there are two). All the belt conveyors and bins are hooded and the air carrying the dust is handled through a dust collector finally discharging into the atmosphere. The approximate coal flow is about 208 tons/hour and the air flow is about 6,550 SCFM.

The crushed coal from the storage bins is transferred to a dryer feed bin (approximate capacity 9 tons) from which it is charged into the Raymond Bowl mill. Hot flue gases from the air heater sweep through the bowl mill carrying the coal dust to a cyclone, the underflow from which is dried pulverized coal (2 percent moisture and 90 percent minus 200 mesh), and sent to dry coal storage. The cyclone discharge goes into a final dust collector and from there into the atmosphere.

The dry coal from the cyclone is transferred by means of screw conveyors into two bins from which another screw conveyor located at the bottom charges the coal to a weigh feeder. This is a belt type with weight totalizers controlling the exact amount of coal charged to the slurry preparation tank. This is essentially a sealed system with vents equipped with filters.

The process system is represented in Figure 8 as a block diagram with the material balance chart showing the streams and their concentrations. There are essentially five input streams into the module and four output streams from the module.

5.1.1.2 Sources of Emissions: The following possible sources of emissions can be identified.


1
2
3
4
5
COAL RECEIVING
RAW COAL STORAGE
PRIMARY CRUSHING
CRUSHED COAL STORAGE
AIR HEATER
DRY COAL STORAGE
CYCLONE
BOWL MILL
9
8
7
6

STREAM / CHARACTER	UNITS	1 RAIN FALL	2 RAW COAL	3 AIR FOR HOODS	4 MAKE UP AIR FOR DRYING	5 FUEL	⑥ DRY COAL	⑦ AIR FROM CYCLONE	⑧ COAL PILE RUNOFF	⑨ AIR FROM DUST COLLECTORS
FLOW RATE	lb/hr	10,000	70,843	441,300	17,265		60,160	27,948	10,000	441,300
STATE		LIQ.	SOLID	GAS	GAS		SOLID	GAS	LIQ.	
CONC. POLLUT.		TRACE								
SOLIDS	mg/ltr								1180	0.2*
LIQUIDS	mg/ltr									
GASES	ppm									

*lb/hr

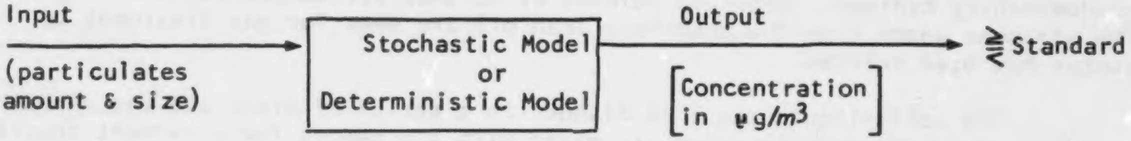
FIG. 8 COAL HANDLING

1.) Coal pile run off, resulting from an exposed coal pile being leached by weather precipitation. The design calls for containment of this runoff by collecting it and pumping to water treatment section. Eventually the treated and cleaned runoff is discharged into the river. The actual quantity of this runoff is very much weather dependant, but is estimated to be equivalent to a flow of 20-25 gpm. The composition of this leachate, however, has not been determined.

2.) Particulate or dust emissions from the coal handling system. Although most conveyors, belts and hoppers are hooded and the exhaust treated by means of filters and dust collectors, a certain amount escapes into the atmosphere. This can be estimated as

$$\begin{bmatrix}\text{particulates}\\ \text{discharged}\end{bmatrix} = \begin{pmatrix}\text{emissions}\\ \text{from}\\ \text{handling}\end{pmatrix} \times \left\{1-\frac{\text{collector efficiency}}{100}\right\}$$

This is the amount that enters the environment and distributes into the surroundings. The concentrations resulting from this particulte emission can then be calculated and compared with the standards.


Input
(particulates amount & size)
Stochastic Model or Deterministic Model
Output
Concentration in μg/m3
≷ Standard

Approximately 60,000 lb/hr are handled. Assuming 0.3 percent of this goes as dust in the handling air and the dust collector efficiency of 99.9 percent, the final emission rate will be 60,000 × $\frac{0.3}{100}$ (1 - 0.999) = 0.18 lb/hr. The flow sheet indicates this quantity as 0.2 lb/hr).

3.) The flue gases used to heat the air in the air heater are finally discharged into the atmosphere. Their acceptability depends upon the fuel used to generate them and its composition. At this time, these are considered clean fuels and thus essentially non-polluting.

5.1.1.3 Character of Emissions: Coal particulates can be assumed to have average properties the same as coal. Coal pile run off probably contains phenols and is acidic, but its composition is undetermined.

5.1.2 Reaction and Primary Separations

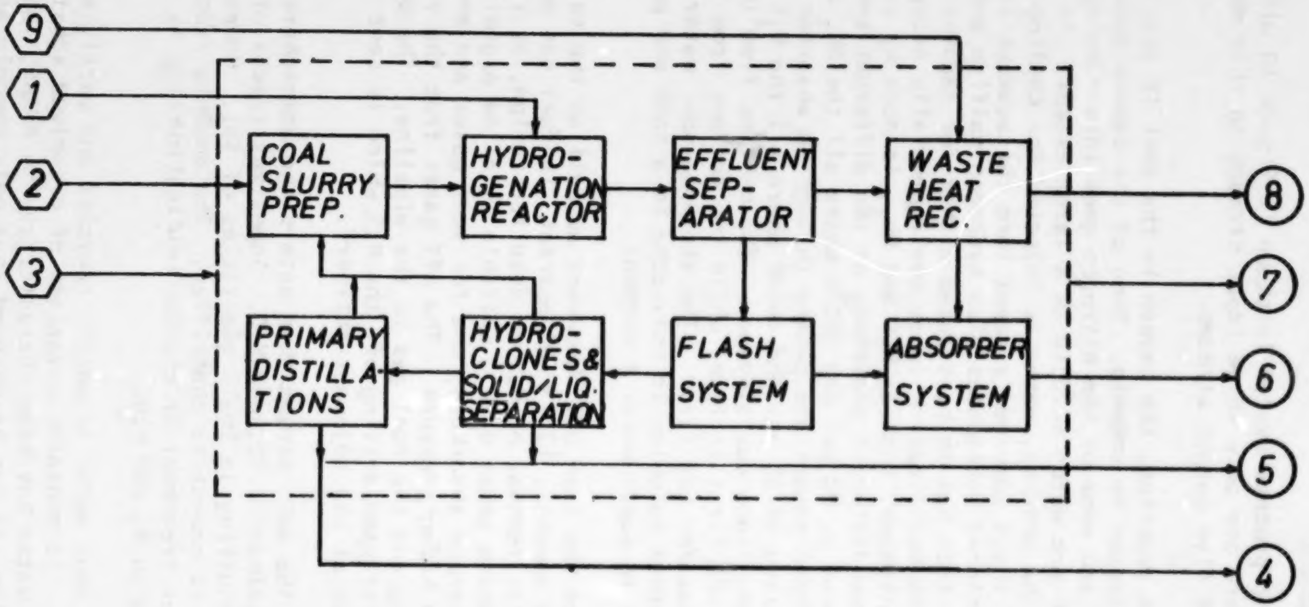
5.1.2.1 Process Description: The process system is shown in Figure 9 as a block diagram together with material balances. For this modular section of reaction and primary separations, there are three principal input streams and four output streams. The waste heat recovery system has an additional input and output stream each, but these are same chemically, as well as flow rate-wise, (water converting to steam).

Dry coal from the weigh feeders is charged to the slurry tank at an average rate of about 45,000 lb/hr where it is slurried with recycle oil of about 100,000 lb/hr and the slurry is pumped under pressure (3000 psi) with some recycle gas through a feed heater where it is heated to about 750°F. This hot slurry along with some more heated recycle gas enters the reactor at the bottom. Ebullating pumps provide for the mixing and uniform temperature distribution in the reactor. The reactor effluent consisting of a three phase mixture of vapor, liquid and solid, is first separated into two fractions, the vapor phase and the solid-liquid phase. The vapor phase is cooled in a waste heat boiler producing process steam. The vapors are further cooled by injecting water and separating the liquid phases. The gases are then scrubbed in an absorber by means of lean oil to remove the lower molecular weight hydrocarbons, and the gases containing predominantly hydrogen (about 82 percent by volume) are compressed and recycled. The stripped gases from the absorbent lean oil are sent for gas treatment to remove hydrogen sulfide.

The solid-liquid phase is flashed in a series of drums and the vapors resulting from the decompression are mixed with the vapors for treatment described above. The liquid-solid mixture is separated by a system of hydroclones and the overflow from these is sent as recycle oil while the underflow is separated for its solids in an anti-solvent process. The liquid is sent for fractionation and solids are sent for bagging and disposed as land fill.

5.1.2.2 Sources of Emissions: The emissions from this section of the process are the flue gases from the various heaters, and any leaks from valves, or due to accidents and ruptures so there is no need to quantify them here. However, there are effluent streams: gaseous, liquid and solid, which are to be treated. These are:

Name	Quantity	Character
Solids residue	13,970 lb/hr (0.3 lb/lb of coal)	Contains ash, unconverted carbon & heavy hydrocarbons
Fuel gas	6,760 lb/hr (0.15 lb/lb of coal)	Contains hydrogen sulfide (10.8 mol percent)
Sour water	24,600 lb/hr (0.54 lb/lb of coal)	Contains H_2S, NH_3 (NH_4) 2S, phenols & other aromatics


9
1
2
3
COAL SLURRY PREP.
HYDRO-GENATION REACTOR
EFFLUENT SEP-ARATOR
WASTE HEAT REC.
PRIMARY DISTILLA-TIONS
HYDRO-CLONES & SOLID/LIQ. SEPARATION
FLASH SYSTEM
ABSORBER SYSTEM
8
7
6
5
4

STREAM / CHARACTER	UNITS	1	2	3	4	5	6	7	8	9
		MAKE UP HYDROGEN	COAL FEED	PROCESS WATER & STEAM	FEED FOR FRACT.	SOLIDS & RESIDS.	FUEL GAS	SOUR WATER	STEAM	BOILER FEED WATER
FLOW RATE	lb/hr	2,387	45,153	20,571	22,787	13,970	7,319	24,597	40,000	40,000
STATE		GAS	SOLID	LIQ.	LIQ.	SOLID	GAS	LIQ.	GAS	LIQ.
CONC. POLLUT.										
SOLIDS	mg/ltr									
LIQUIDS	mg/ltr									
GASES	ppm									

FIG. 9 REACTION & PRIMARY SEPARATIONS

]

5.1.3 Sour Water and Gas Treatment

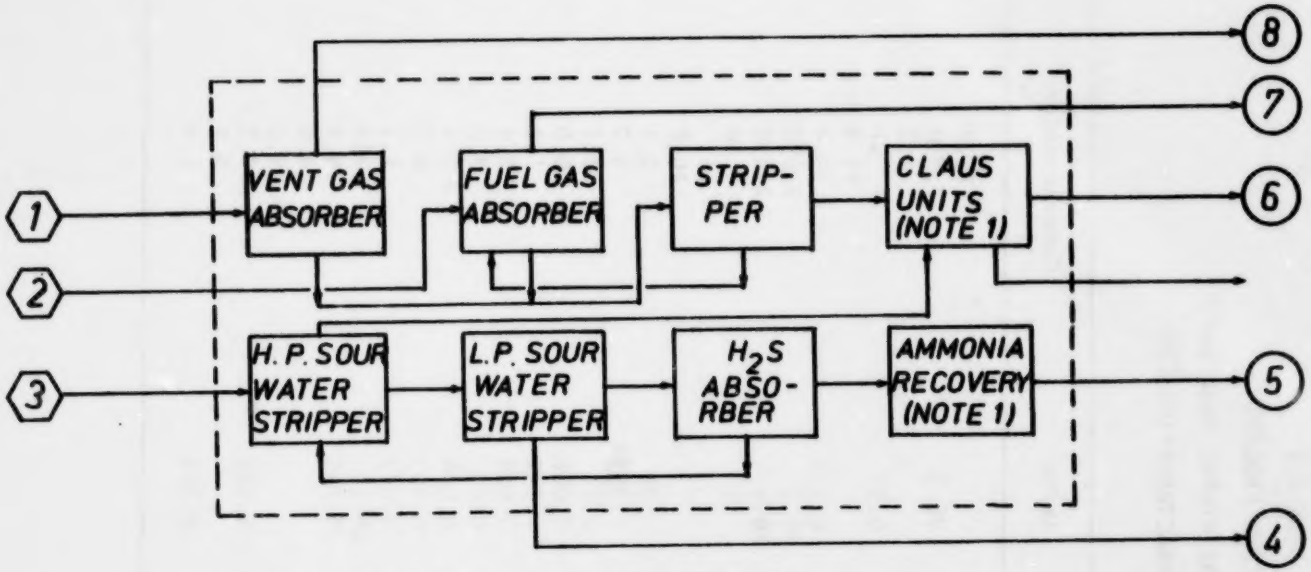
5.1.3.1 Process Description: The process system is shown in Figure 10 with the material balance also shown. There are only three input streams to this module: two gases and one sour water, and five output streams.

During the hydrogenation reaction, the oxygen in the coal is partly hydrogenated to water and the nitrogen to ammonia. Some of the oxygen appears in oxyhydro-carbons (phenols, etc.) and some of the nitrogen goes into forming pyridine, piccolines, etc., which are water soluble to a large extent. In addition to the water formed in the process, water is injected for cooling purposes at several points. All of these combined streams form the aqueous layer, which contains all the above mentioned substances plus hydrogen sulfide and ammonia. This is the sour water that has to be treated either for recovery of these substances or their suitable modification in an environmentally acceptable way. Recovery of some of these streams, such as H_2S and NH_3, is done by steam stripping the sour water under two different pressures at two different temperatures. The first stripper operates at 88 psi and 300°F where all the NH_3 and the remaining H_2S are driven off. These vapors are passed through an absorber with a partial reflux condenser operating at 39 psi and 164°F where all the H_2S is retained in the liquid phase and NH_3 flows out as vapor. The bottoms from this absorber are mixed with feed to the first stripper while the bottoms from the second stripper are used as reflux for the first. The stripped sour water containing sulfides, phenols, and other solubles is collected in a tank and partly recycled; the other part is sent to waste water treatment.

The fuel gas coming from the lean oil absorbers as well as the various vents contains H_2S in appreciable amounts; 10.8 mol percent in fuel gas and 3.8 mol percent in vent gas. This removal of H_2S or desulfurization, as it is called, is achieved by washing these gases with a suitable alkaline organic like diethanolamine (DEA) in separate absorbers, one for vent gases and another for fuel gas operating at a much higher pressure. The off gases from the vent gas absorber are sent for flaring and the fuel gas to the pipeline. The DEA solution containing the H_2S is stripped, driving off the H_2S, which is sent to Claus units for partial oxidation at the adjacent refinery.

5.1.3.2 Sources of Emissions: The only stream that enters the atmosphere directly is the flare which contains primarily CO_2 and H_2O. Sometimes traces of H_2S may escape into the flare gas resulting in small quantities of SO_2. However, this is so small and infrequent that it cannot be quantified. The ammonia from the second stripper of the sour water treatment or the denitrification step is sent into a boiler furnace and burned to N_2 and H_2O.

The effluent stream of sour water is partly recycled and partly sent to the waste water treatment plant. It contains a variety of dissolved substances. For example the unstripped foul water has been characterized by AWARE, Inc., as given in Table 1. After stripping, it can be assumed that only ammonia and sulfide are removed and everything else stays in the water. In the pilot plant, only 10,000 lb/hr of this stripped water are to be sent for waste treatment and the remaining 17,300 are to be recycled. Thus, for a flow rate of 10,000 lb/hr, the


1
2
3
VENT GAS ABSORBER
FUEL GAS ABSORBER
STRIP-PER
CLAUS UNITS (NOTE 1)
H.P. SOUR WATER STRIPPER
L.P. SOUR WATER STRIPPER
H_2S ABSO-RBER
AMMONIA RECOVERY (NOTE 1)
8
7
6
5
4

(NOTE 1. NOT INCLUDED IN THE PILOT PLANT.)

STREAM / CHARACTER	UNITS	① SOUR VENT GAS	② SOUR FUEL GAS	③ SOUR WATER	④ STRIPPED SOUR WATER	⑤ AMMONIA	⑥ SULFUR	⑦ CLEAN FUEL GAS	⑧ FLARE
FLOW RATE	lb/hr	562	6,757	28,076	27,294	286	1,796	4,943	508
STATE		GAS	GAS	LIQ.	LIQ.	GAS	SOLID	GAS	GAS
CONC. POLLUT									
SOLIDS	mg/ltr								
LIQUIDS	mg/ltr								
GASES	ppm	3.84*	10.78*						
OTHER									

*MOL % H_2S

FIG. 10 DESULFURIZATION & DENITRIFICATION.

TABLE 1

H-COAL PROCESS
INITIAL UNSTRIPPED FOUL WATER CHARACTERISTICS (14)

Parameter	lb/hr	Concentration
COD (%)		35.7
Phenol	78.3	7,830
Ammonia (%)		2.8
Organic nitrogen	0.51	51
Sulfide (%)		11.8
Oil and grease	0.334	33.4
Total solids	26.9	2,690
Dissolved solids	26.9	2,690
Suspended solids	.2	20
Volatile suspended solids		nil
pH (pH units)		10.8
Phosphate	.02	2.1
Cyanide	0.0037	3.7
Cr	0.01	0.1
Cd	0.008	0.8
Fe	0.012	1.2
Pb	0.029	2.9
Al	0.025	2.5
Cu	0.004	0.4
Mg	0.007	0.7
Ni	0.017	1.7
SO_4	24.2	252
Ca	0.043	4.3
V		1.0
Ti		1.0
Na	0.105	10.5
Mo		0.5
Co	0.014	1.4

a. Composite sample.

b. Concentration shown in mg/l, unless otherwise designated.

effluent stream will have the characteristics given in Table 1 as lb/hr.

5.1.4 Waste Water Treatment

The process schematic is shown in Figure 11.

5.1.4.1 Process Description: The process design parameters were based on the results of the characterization and bench-scale investigations reported in reference No. 14. Influent flow and temperature information was supplied by HRI-Engineering and Ashland Oil. The basic process flow sequence was developed by AWARE through discussions with HRI-Engineering and Ashland Oil. In this section design parameters for the individual unit processes are presented. The design was developed to treat the waste water anticipated from the H-Coal pilot plant. The H-Coal pilot facility is being designed for a 2-year operation. Since this is a pilot facility, it is being designed for an on-stream factor of 50 percent. The H-Coal facility will be operated under a wide range of conditions. Several types of coal will be processed and operating parameters will be varied to obtain various petroleum products. The resulting process related waste waters are anticipated to vary, depending on the operational mode employed.

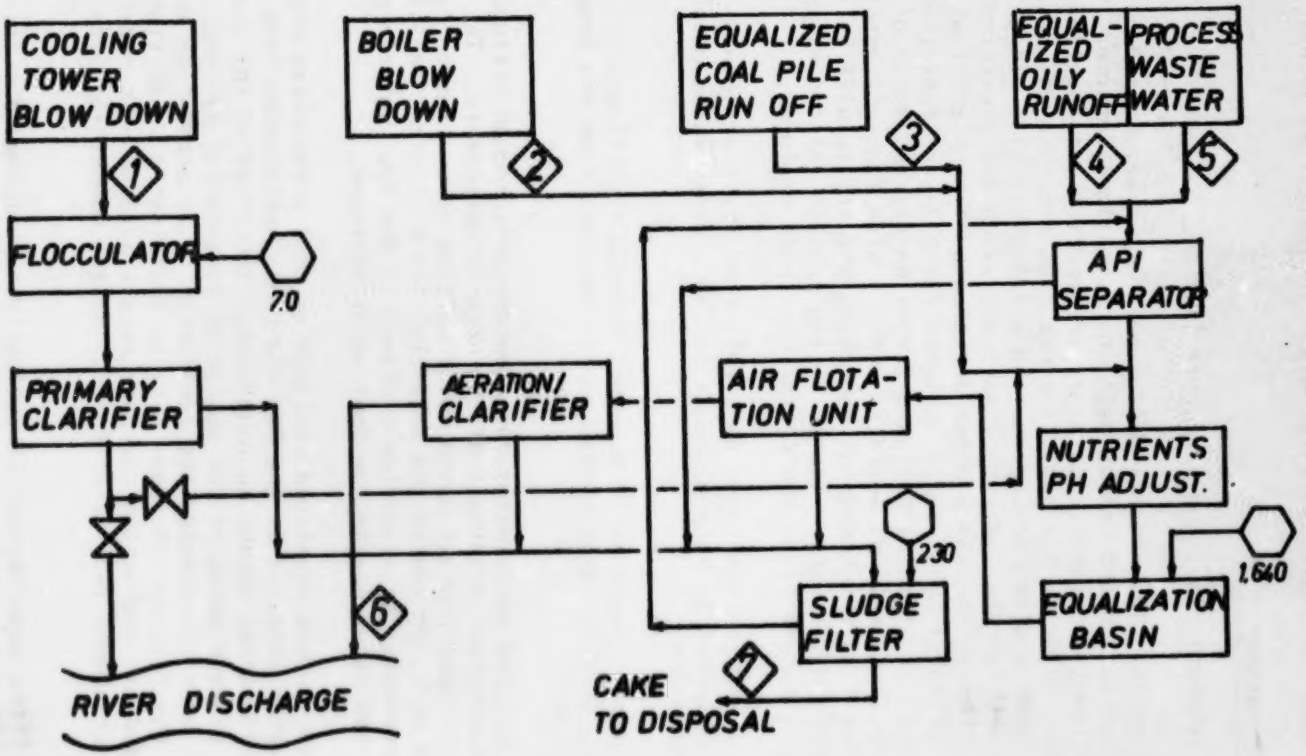
The design information developed as a result of the experimental investigations can be considered to be applicable to the process waste waters from the pilot plant, provided that:

1. The raw process waste water does not deviate significantly from the unstripped process waste water samples received from the process development unit.

2. The raw stripped waste water must contain only enough nitrogen to achieve biological treatment of the organic components. The maximum stripped process waste water sulfide concentration cannot exceed 50 mg/l, otherwise the potential for biological inhibition will be present. No significant change in the foul water organic strength can occur due to the foul water stripper.

The process design was developed recognizing that differences may exist in the process waste water produced by the PDU and those anticipated from the pilot plant. Since these differences cannot be completely identified at the present time, it is necessary to base parts of the design on judgemental factors. Operating flexibilities have been integrated into the design in an attempt to accommodate these differences and the frequent shutdown periods anticipated. Additional flexibility has been included for evaluating various process arrangements necessitated by the need to design treatment facilities for subsequent commercial size H-Coal plants.

As a result of the experimental investigations performed and discussions between HRI-Engineering, Ashland Oil, and AWARE, the following decisions were made regarding the waste water treatment plant design (14):


COOLING TOWER BLOW DOWN
BOILER BLOW DOWN
EQUALIZED COAL PILE RUN OFF
EQUAL-IZED OILY RUNOFF
PROCESS WASTE WATER
1
2
3
4
5
FLOCCULATOR
7.0
API SEPARATOR
PRIMARY CLARIFIER
AERATION/ CLARIFIER
AIR FLOTA-TION UNIT
NUTRIENTS PH ADJUST.
230
1,640
6
SLUDGE FILTER
EQUALIZATION BASIN
7
CAKE TO DISPOSAL
RIVER DISCHARGE

	1	2	3	4	5	6	7
STREAM / COMPON.	COOLING TOWER BLOW DOWN	BOILER BLOW DOWN	COAL PILE RUN OFF	OILY RUN OFF	PROCESS WASTE WATER	CLEAN WATER FOR DISCHARGE	CAKE FOR DISPOSAL
WATER	25,000	5,500	12,500$_{max}$	15,000$_{max}$	10,000	68,198	
SOLIDS							1,678
TOTAL	25,000	5,500	12,500	15,000	10,000	68,198	1,678

FIG. 1 1 WATER TREATMENT PROCESS SCHEMATIC.

1. The process waste water and the non-process waste waters (oily water runoff, coal pile runoff, boiler blowdown, and the cooling tower blowdown) are to be combined prior to biological treatment. The non-process waste waters will provide dilution of the concentrated process waste streams.

2. The process waste water will be stripped to reduce the ammonia and sulfide concentrations to those levels compatible with an activated sludge system designed to treat organic materials. The organic strength of the foul water will not be significantly altered by stripping.

3. The oily water runoff and the stripped process waste water will be combined and pretreated to reduce the waste water oil and grease. An emulsion-breaking system is to be included to handle possible emulsions resulting from the combined process waste water and oily water runoff streams.

4. Floated oil removed from the surface of the API separator will be discharged to the light slop oil system. The API separator bottoms will be combined with the aerobically digested waste activated sludge prior to pressure filtration.

5. The cooling tower blowdown is to be pretreated for chromium reduction prior to biological treatment. An electro-chemical chromate reduction unit will be used followed by pH adjustment, flocculation, and clarification. The metal hydroxide sludge removed by clarification will be combined with the aerobically digested waste activated sludge prior to pressure filtration.

6. The coal pile runoff and oily water runoff are to be equalized prior to entering the treatment system.

7. Equalization facilities are to be provided to minimize the potential for treatment plant upsets or inconsistent operation, since the variability of the process waste water to be generated by the H-Coal pilot plant is unknown.

8. Storage facilities are to be installed to provide feed necessary to maintain an acclimated sludge in the biological treatment system during extended pilot plant shutdowns.

9. The combined waste water from the equalization basin is to be pretreated to reduce the oil and grease content using an induced air flotation unit. The induced air unit skimmings are to be combined with the aerobically digested waste activated sludge prior to pressure filtration.

10. Biological treatment will consist of a single-stage activated sludge system. The system will be designed to ensure reasonable operating

flexibility. Effluent from the biological system will be combined with the treated sanitary waste water and runoff from uncontaminated plant areas prior to discharge to the Big Sandy River.

11. To conserve heat, a submerged aeration system will be employed. During the winter operating months, the cooling tower blowdown will be discharged from the hotter side of the cooling tower. During the summer months, the blowdown will be discharged from the cooler side.

12. Waste activated sludge will be thickened using a gravity thickener. The thickened sludge will be stabilized in an aerobic digester.

13. Aerobically digested waste activated sludge will be combined with the API separator bottom sludge, the metal hydroxide sludge from the cooling tower blowdown pretreatment system, and the skimmings from the induced air flotation unit. The combined sludge will be chemically conditioned and dewatered using a pressure filter operated at 225 psig. The dewatered cake will be landfilled.

The characteristics of the individual and combined H-Coal waste waters are presented in Table 2.

Other significant waste water constituents not enumerated in Table 2, but anticipated to be included in the discharge permit are oil and grease and ammonia nitrogen. For the purpose of calculating the combined raw waste water load, an oil and grease concentration of 80 mg/l was selected based on measurements during the laboratory simulation and differences anticipated in the pilot plant. The unstripped foul water will have an ammonia nitrogen concentration of 21,200 mg/l, which will all be stripped prior to biological treatment.

A summary of the combined raw waste water load, the design effluent criteria and the recommended discharge limitation are given in Table 3. The steady-state effluent levels were used as the basis on which to transmit the treatability data into the process design. However, for the experimental reactors operated at the same conditions under which the steady-state criteria are achieved, the variability in influent waste load, temperature, and composition observed during the treatability phase of this investigation were felt to be similar to that variability which would be experienced in the pilot plant.

5.1.5 Waste Solids Treatment

5.1.5.1 Process Description: Waste solids or solid products with no current market value are produced in the H-Coal process in two operations. One, when the hydroclone underflow is solvent deashed separating the solids and the liquids. The solids contain coal ash, unconverted carbon and heavy hydrocarbons. The other source of solids for disposal is the vacuum tower bottoms which are solidified and sent for disposal as land fill. The hot residue from the vacuum tower bottom is partially separated into liquid and solid fractions and the solid fraction, still

TABLE 2

CHARACTERISTICS OF INDIVIDUAL WASTESTREAMS (14)

	Winter						Summer					
Wastestream	Flow (gpm)	SS (lb/day)	COD (lb/day)	BOD[a] (lb/day)	Phenol[b] (lb/day)	Temp (°F)	Flow (gpm)	SS (lb/day)	COD (lb/day)	BOD[a] (lb/day)	Phenol[b] (lb/day)	Temp (°F)
Process Wastestream												
Foul Water Stripped	15.5	4	4,935	-	-	90	15.5	4	4,935	-	-	110
Stream 52	0.8	5	40	-	-	90	0.8	5	40	-	-	110
Stream 50	3.7	2	15	-	-	90	3.7	2	15	-	-	110
Non Process Wastestream												
Cooling Tower Blowdown[c]	50	2	5	-	-	100	50	2	5	-	-	85
Boiler Blowdown	10.5	2	10	-	-	212	10.5	.2	10	-	-	212
Coal Pile Runoff	20	155	60	-	-	33	25	195	75	-	-	75
Oily Water Runoff	14	40	25	-	-	33	30	90	55	-	-	75
Combined Total	115	210	5,090	3,180	1,180		136	300	5,136	3,210	1,190	

[a] Based on the correlation of the wastewater total and COD developed during this investigation; $BOD_T = 0.66\ COD_T - 180$.

[b] Based on the BOD/Phenol correlation developed during this investigation; $Phenol = 0.37\ BOD_T$.

[c] Hot side blowdown in the winter; cold side blowdown in the summer.

TABLE 3

SUMMARY OF RAW WASTE LOAD, DESIGN, AND DISCHARGE CRITERIA (14)

	Raw waste loading (lb/day)		Effluent (lb/day)		
			Design steady-state Criteria[d]	Recommended discharge limitation	
	Winter	Summer		30-Day avg.	Max.
Flow, mgd	0.165	0.195	--	--	--
BOD_T	3,180	3,210	82	180	360
Phenol	1,180	1,190	1.6	10.8	21.6
Suspended solids	210	300	82	242	484
Oil and grease	110[a]	130[a]	25	24	48
Ammonia-nitrogen					
Unstripped[b]	3,950	3,950	--	--	--
Stripped[c]	0	0	16	16.3	32.6

[a] An oil and grease concentration of 80 mg/l assumed.

[b] Ammonia nitrogen present in the process wastewater prior to pretreatment by steam stripper.

[c] Ammonia nitrogen present in the combined wastewater prior to biological treatment following steam stripping.

[d] Steady-state criteria based on results achieved during steady-state operation of bench-scale units. This effluent level will not be achieved in the pilot facility due to the anticipated variability associated with the H-Coal process and the manner in which the pilot plant will be operated.

a fluid, is discharged onto a belt cooled with water sprays. As the belt cools the solidified material is chipped off the belt and transported to a silo from which it is bagged and trucked out for landfill purposes. The equipment and operation have to be tested and experimented for suitable operation and optimum conditions. The tentative operating conditions, however, call for a feed capacity of 6700 lb/hr. at a belt speed of about 160 fpm. Feed inlet temperature is about 590°F and the cake discharges at 140°F. Cooling water rates are about 255 gpm under spray and about 20 gpm above the belt.

5.1.5.2 Emissions: As the mass cools, certain amount of vapors evolve and these are collected and condensed. The liquid is recycled into the system. The exhaust still may contain traces of hydrocarbons, perhaps harmless, but will be very odorous. The cake itself contains a variety of heavy aromatics. The expected flow rate of vacuum tower bottoms is about 15,300 lb/hr.

5.1.6 Catalyst Handling

5.1.6.1 Process Description: In order to maintain a certain catalyst activity, the catalyst in the pilot plant is periodically withdrawn and replenished with fresh catalyst. The operation is designed as batchwise and manual. A slip stream from the reactor is taken out at given intervals and discharged into one of two tanks. The slurry is then filtered and the solid spent catalyst is disposed. Fresh catalyst is added from the top of the reactor via a system of hoppers and feed tanks.

Potential source of emission is the solid spent catalyst containing heavy hydrocarbons and coal deposit on the catalyst. The ultimate fate of this spent catalyst is not well defined. At an approximate ratio of 1 lb of catalyst per ton of coal the quantity of spent catalyst produced will be about 600 lb/day.

5.2 CONTROL TECHNOLOGY FOR THE PILOT PLANT

As has already been pointed out, the pilot plant is not an integrated operation, but is located adjacent to a large oil refinery and is supported by it. Of the three principal effluents from the pilot plant, the gaseous streams containing H_2S are combined and sent to the refinery for treatment. Another gas stream containing ammonia is sent to the boiler furnace and burned to yield N_2 and H_2O as combustion products.

The liquid waste streams consisting of process waste water, cooling tower blowdown and coal pile run-off, are all combined in an equalization tank and treated in a series of steps as described in the previous section. The sludge from this treatment in the pilot plant is disposed of as landfill.

The solid wastes from the pilot plant emanate from three process units: 1) the Lummus anti-solvent deashing system; 2) the cooled vacuum tower bottoms; and 3) the spent catalyst. The nature of all these three wastes is that they contain heavy, coal-derived, carbon compounds in addition to the inorganic compounds present in the coal ash. At the present time, the process design of the pilot plant calls for disposal of these wastes only as landfill. This method is based on some tests carried out on these materials for their leachability. They appear not to be leachable. However, it is believed that the spent catalyst can be regenerated and the vacuum tower bottoms can be used to produce hydrogen in a gasifier of the Texaco type.

5.3 ANALYSIS OF THE PILOT PLANT CONTROL TECHNOLOGY

Since the mission of the pilot plant is to establish the technology of coal conversion and prove the process, the principal emphasis is naturally on the process itself. That is, the emphasis is predominantly upon studies concerning the reaction, product separations, catalyst life, etc. As regards the control technology, it is usually assumed to be off-the-shelf type and even presumed proven.

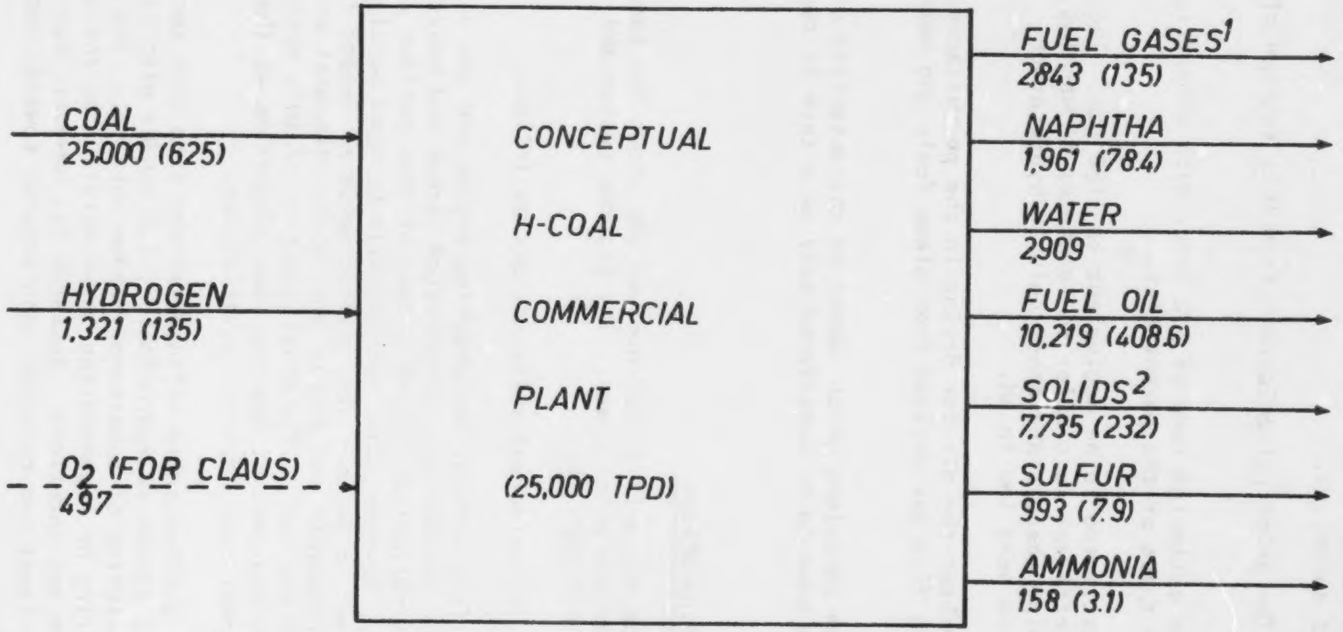
In these pilot plants, accordingly, there is little control technology per se because all the effluent streams are channeled to the adjacent refinery where they are probably mixed with those of the refinery and treated. While it is difficult to analyze a situation like that, it still shows that these wastes are treatable and the treatment is similar to the practice existing in petroleum refineries at the present time.

On the other hand, because of the nature of the operation and the objectives, the pilot plant operation may be more often in an unsteady state than in a steady state. Under these conditions the characterization of the effluents and emissions becomes very difficult. Also, the control technology, whatever it is, demonstrates an erratic mode of operation rendering any analysis very problematic.

5.4 EMISSIONS FROM COMMERCIAL PLANT

Any scaling up of pilot plant information to commercial plant size involves several judgments. These depend upon the nature of information available on the item that is to be scaled up. In the case of coal liquefaction plants it is rendered more complex because the raw material characteristics (coal properties) are not uniform. For purposes of estimating emissions, however, a linear scaling up of the quantities should suffice. Furthermore, as has been mentioned in Section 5.1, the process systems will also be the same as in the case of the pilot plant except for three more added systems for hydrogen manufacture, power and utilities, and oxygen plant. These will be considered along with the six analyzed for the pilot plant.

The overall material balance for a conceptual commercial H-Coal plant of 25,000 tons of coal per day is shown in Figure 12. This is shown only for one mode of operation, namely the fuel oil mode using Illinois #6 coal.


COAL
25,000 (625)
HYDROGEN
1,321 (135)
O$_2$ (FOR CLAUS)
497
CONCEPTUAL
H-COAL
COMMERCIAL
PLANT
(25,000 TPD)
FUEL GASES^1
2,843 (135)
NAPHTHA
1,961 (78.4)
WATER
2,909
FUEL OIL
10,219 (408.6)
SOLIDS^2
7,735 (232)
SULFUR
993 (7.9)
AMMONIA
158 (3.1)

1. TONS PER DAY. THE NUMBERS IN ( ) REPRESENT BTU'S IN BILLIONS.

2. CAN BE USED TO PRODUCE HYDROGEN.

FIG. 12 OVERALL MATERIAL BALANCE:
FUEL OIL MODE OF OPERATION
ILLINOIS #6 COAL.

5.4.1 Coal Handling and Preparation

Assuming the process steps are similar to those in the pilot plant for this throughput of coal, the process system is shown in Figure 13 with a material balance chart showing the emissions.

5.4.1.1 Principal Emissions: The principal emissions from this section of the process are:

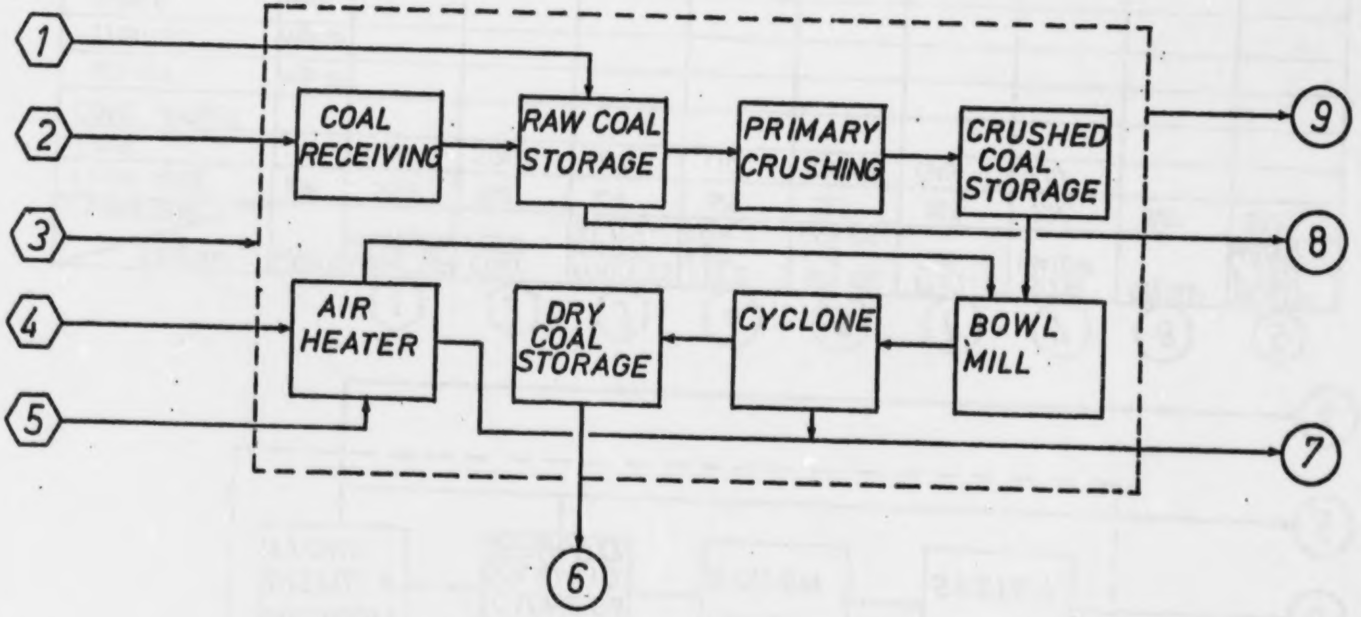
1. Particulates, at an estimated rate of 9.2 lb/hr with properties closely resembling those of the parent coal.
2. Coal pile runoff estimated to be equivalent to 1150 gpm. The character of this effluent is similar to leachates of washing operations containing phenols and other soluble hydrocarbon compounds and can be very low in pH.
3. Flue gases used to heat the air for drying in the pulverizers. This is essentially flue gas derived from clean fuels and hence non-polluting.
4. Spills and fugitive emissions which cannot be characterized or quantified. These have to be considered only on a case by case basis.

5.4.2 Reaction and Primary Separations

Process description and the unit steps involved are about the same as described in Subsection 5.1 for the pilot plant. The process system and the material stream flows are shown in Figure 14.

5.4.2.1 Principal Emissions: The principal emissions are as follows:

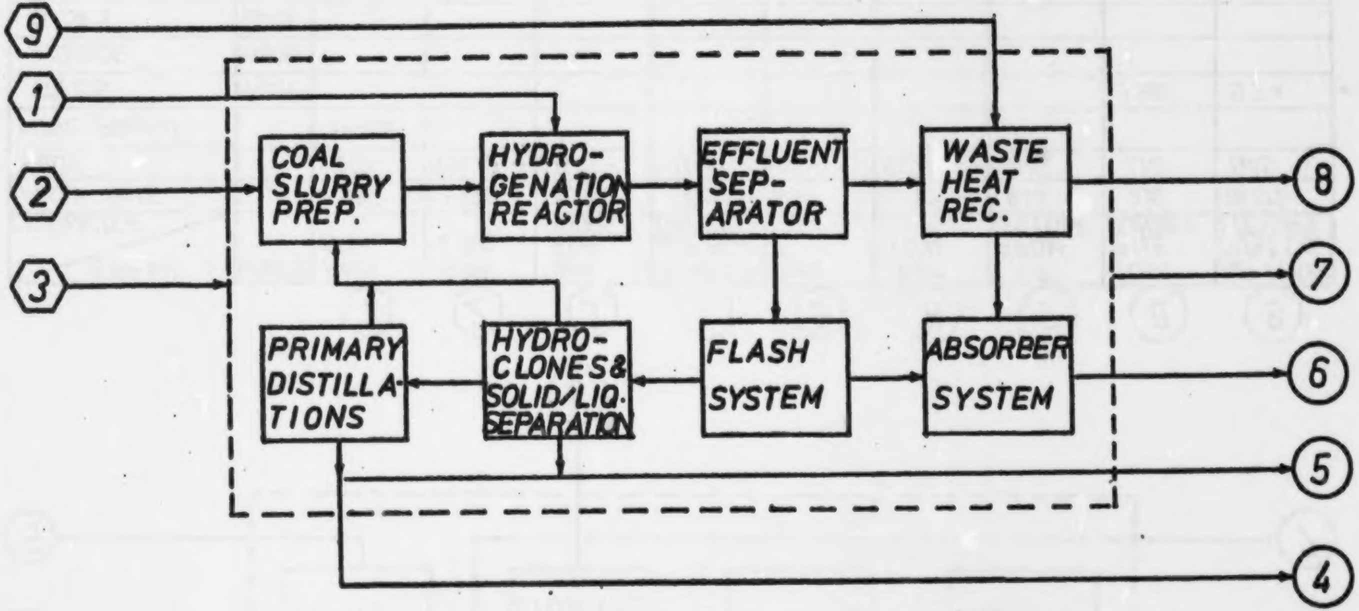
1. The solid residue from antisolvent deashing system and the vacuum tower bottoms which contain ash, unconverted carbon and heavy hydrocarbons. The estimated rate of output of this residue is about 322 tons per hour. However, this residue will be used partly to produce hydrogen and to recover the heating value as needed in the process so that ultimately the solids that go for disposal are only the ash content of the coal. The final quantity of this waste stream is about 110 tons per hour and it has the same properties as that of ash from conventional coal burning installations.
2. Spent catalyst is another solid effluent stream from this section. The amount of this stream is approximately 1.0 ton/hr with 52 percent of the solids consisting of cobalt-molybdenum catalyst. The current methods of recovering or regenerating these metals from the spent catalyst are vague and undefined. Research is, however, being carried out by at least one catalyst manufacturer towards regenerating


1
2
3
4
5
COAL RECEIVING
RAW COAL STORAGE
PRIMARY CRUSHING
CRUSHED COAL STORAGE
AIR HEATER
DRY COAL STORAGE
CYCLONE
BOWL MILL
9
8
7
6

STREAM / CHARACTER	UNITS	① RAIN FALL	② RAW COAL	③ AIR FOR HOODS	④ MAKE UP AIR FOR DRYING	⑤ FUEL	⑥ DRY COAL	⑦ AIR FROM CYCLONE	⑧ COAL PILE RUNOFF	⑨ AIR FROM DUST COLLECTORS
FLOW RATE	tph	230	1,634	10,177	398		1,387	644	230	10,177
STATE		LIQ	SOLID	GAS	GAS		SOLID	GAS	LIQ	GAS
CONC. POLLUT.		TRACE								
SOLIDS	mg/ltr									
LIQUIDS	mg/ltr								1180	9.2 *
GASES	ppm									

* = lb/hr

FIG. 13 COAL HANDLING


9
1
2
3
COAL SLURRY PREP.
HYDRO-GENATION REACTOR
EFFLUENT SEP-ARATOR
WASTE HEAT REC.
PRIMARY DISTILLA-TIONS
HYDRO-CLONES & SOLID/LIQ. SEPARATION
FLASH SYSTEM
ABSORBER SYSTEM
8
7
6
5
4

STREAM / CHARACTER	UNITS	① MAKE UP HYDROGEN	② COAL FEED	③ PROCESS WATER & STEAM	④ FEED FOR FRACT.	⑤ SOLIDS & RESIDS	⑥ FUEL GAS	⑦ SOUR WATER	⑧ STEAM	⑨ BOILER FEED WATER
FLOW RATE	tph	55.0	1041	474	525	322	169	554	922	922
STATE		GAS	SOLID	LIQ	LIQ	SOLID	GAS	LIQ		
CONC. POLLUT.										
SOLIDS	mg/ltr									
LIQUIDS	mg/ltr									
GASES	ppm									

FIG. 14 REACTION & PRIMARY SEPARATIONS

the catalyst for reuse. No specific data or technology is yet available. Therefore, this spent catalyst disposal must be considered as a waste, and so treated. One such system can be conceived as first extracting the catalyst with a solvent followed by washing and then drying the residue. The dried spent catalyst can be sold for its metal value. The recovered hydrocarbons and the solvent can be recycled into the system.

5.4.3 Desulfurization and Denitrification

The unit process steps are essentially the same as described in Section 5.1 and consist primarily of absorption and stripping in case of fuel gas streams and only stripping in case of sour water streams. The process schematic and effluent streams are shown in Figure 15. The hydrogen sulfide-rich gases are sent to Claus units for partial oxidation to elemental sulfur. The tail gases, however, must be treated to meet the existing environmental standards. The control technology for this treatment is discussed in detail in Section 7. It is sufficient to mention here that this technology is not only proven but also is widely accepted and so must be considered as off-the-shelf. Only the size of the system of Claus units followed by tail gas treatment are somewhat larger than normally employed units. The system must be capable of handling about 28 million SCFD of rich (about 80 percent) H_2S gas.

The principal emissions are:

1. The combusted products from flares which containonly CO_2, H_2O and traces of SO_2 and particulates (as soot) in amounts of about 60 tons/hour.

2. Sulfur and ammonia as products in the amounts of 1,000 and 150 tons/day of each.

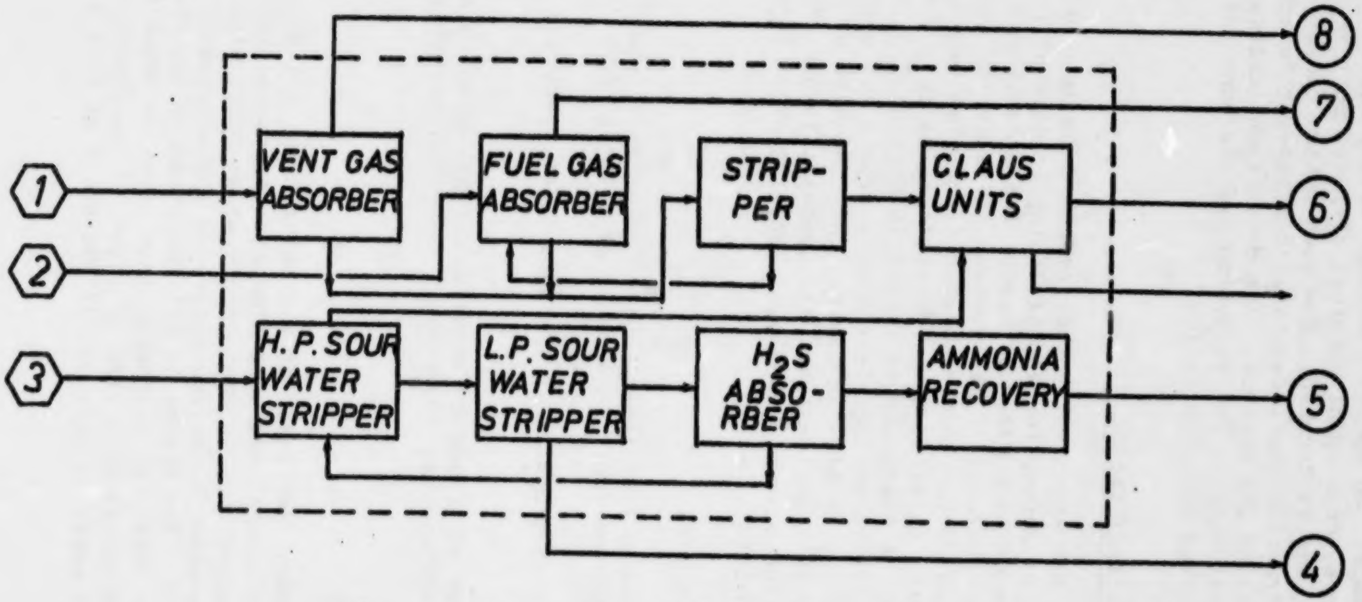
3. Stripped sour water at a rate of about 2,500 gpm of which approximately two-thirds can be reused without any treatment. The other one-third is sent to waste water treatment.

5.4.4 Waste Water Treatment

The waste water treatment designed for the pilot plant was discussed in Section 5.1.4. In the case of water treatment plants, scaling-up from pilot plant data is not the best procedure, but in the absence of anything else, this is acceptable. Such a scaled-up plant with flow rates and the conceptual process schematics are shown in Figure 16. The figure is self explanatory and the two effluent streams are: 1) clean water for discharge into river at about 6,250 gpm and 2) the solid cake for disposal at a rate of about 40 tons/hour. The method of disposal of this solid waste is only as fill material at this time.

5.4.5 Hydrogen Production

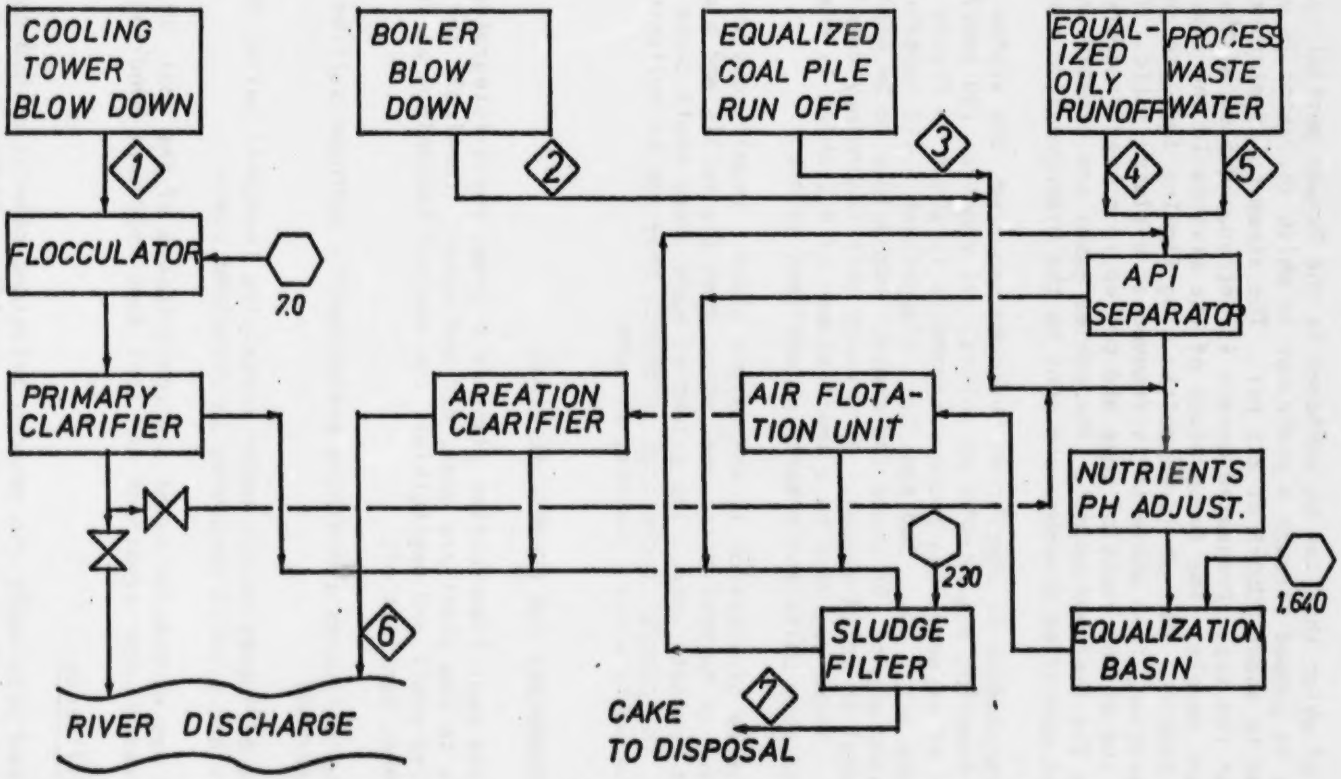
The hydrogen required for hydrogenation is planned to be produced from the solids fraction of the LUMMUS-System and the solidified vacuum tower bottoms.


1
2
3
VENT GAS ABSORBER
FUEL GAS ABSORBER
STRIP-PER
CLAUS UNITS
H. P. SOUR WATER STRIPPER
L. P. SOUR WATER STRIPPER
H_2S ABSO-RBER
AMMONIA RECOVERY
8
7
6
5
4

STREAM / CHARACTER	UNITS	① SOUR VENT GAS	② SOUR FUEL GAS	③ SOUR WATER	④ STRIPPED SOUR WATER	⑤ AMMONIA	⑥ SULFUR	⑦ CLEAN FUEL GAS	⑧ FLARE
FLOW RATE	tph	13	156	647	629	6.6	41.4	114	12
STATE		GAS	GAS	LIQ	LIQ	GAS	SOLID	GAS	GAS
CONC. POLLUT.									
SOLIDS	mg/ltr								
LIQUIDS	mg/ltr								
GASES	ppm	3.84*	10.78*						
OTHER									

*mol% H_2S

FIG. 15 DESULFURIZATION & DENITRIFICATION


COOLING TOWER BLOW DOWN
BOILER BLOW DOWN
EQUALIZED COAL PILE RUN OFF
EQUAL-IZED OILY RUNOFF
PROCESS WASTE WATER
1
2
3
4
5
FLOCCULATOR
7.0
API SEPARATOR
PRIMARY CLARIFIER
AREATION CLARIFIER
AIR FLOTA-TION UNIT
NUTRIENTS PH ADJUST.
230
1.640
SLUDGE FILTER
EQUALIZATION BASIN
6
7
RIVER DISCHARGE
CAKE TO DISPOSAL

STREAM / COMPON	1 COOLING TOWER BLOW DOWN	2 BOILER BLOW DOWN	3 COAL PILE RUN OFF	4 OILY RUN OFF	5 PROCESS WASTE WATER	6 CLEAN WATER FOR DISCHARGE	7 CAKE FOR DISPOSAL
WATER •	2300	500	1150	1380	920	6250	
SOLIDS							40 t/h
TOTAL							

•gpm

FIG. 16 WATER TREATMENT PROCESS SCHEMATIC

The process by means of which this can be achieved is the Texaco partial oxidation. A water-solids slurry is pumped through a preheater in which the water is vaporized and the mixture heated to about 1000°F at 225 psi. The steam-solid mixture then enters the gasifier at the top. Preheated oxygen is introduced also at the top by means of a different nozzle. The temperature of the mixture in the reaction zone reached 2000° - 2500°F. The ash forms molten slag flowing down the gasifier walls into a quench section, from where it is removed as a glassy solid. The gases are removed from the end of the reaction zone and cooled in a heat recovery system for preheating the feed and oxygen. The cooled gases are treated and compressed to the reactor operating pressure and sent to the hydrogenation section.

In order to produce 60 tons/hr of hydrogen required, the system should be capable of handling 325 tons/hr of solids. It requires 130 tons/hr of steam and 275 tons/hr of oxygen. The process schematic is shown in Figure 17. The principal emissions are: CO_2 - 560 tons/hr., slagged ash - 110 tons/hr and nitrogen from the oxygen plant. Of these the control technology to be employed is only for the disposal of solid wastes. At present this technology consists of suitable landfill. There can also be a small stream of H_2S which is mixed with that from the refinery units and treated as outlined before.

Another source of emission is the oxygen plant. Usually oxygen plants do not have any serious or harmful emissions, other than the spills and blowdowns of the lubricants and coolants used. The extent of harm these could cause has not been determined, but, for control technology purposes, they can be collected and treated along with the waste water treatment streams.

5.5 CONTROL TECHNOLOGY FOR COMMERCIAL PLANT

Assuming any coal liquefaction plant is a grass roots-integrated plant i.e., the only inputs to the plant are coal, air and water; (chemicals and catalyst are considered small and negligible), the control technology as far as emissions are concerned, consists of:

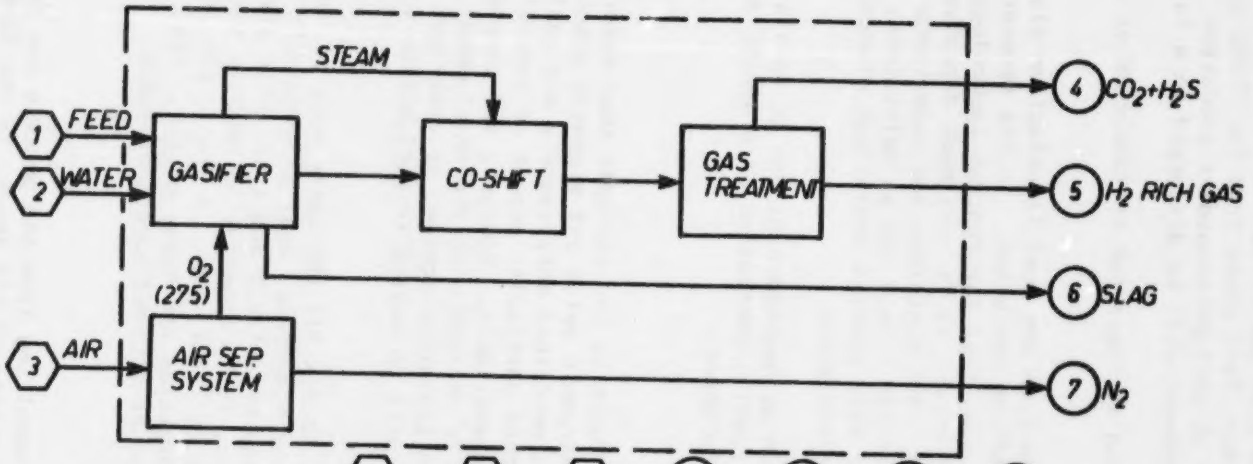
1. gaseous effluents containing predominantly hydrogen sulfide and hydrocarbons

2. liquid effluents mainly water containing inorganic salts, heavy metals and organic compounds in dissolved state

3. solid wastes consisting of ash constituents of the coal, sludges from waste water treatment and coal dust from coal handling.

5.5.1 Gaseous Effluents

As mentioned previously the gaseous emissions consist of hydrogen sulfide, ammonia and some hydrocarbons. Hydrogen sulfide, formed from the sulfur in coal, appears in the two streams of fuel gas and sour water. The fuel gas is scrubbed with an amine solvent like DEA, which is subsequently stripped to release the hydrogen sulfide. The sour water which contains both ammonia and


1
FEED
2
WATER
3
AIR
GASIFIER
STEAM
CO-SHIFT
GAS TREATMENT
O_2 (275)
AIR SEP. SYSTEM
4 CO_2+H_2S
5 H_2 RICH GAS
6 SLAG
7 N_2

CHARACTER \ STREAM	UNITS	1 FEED (VAC. TWR BOTTOMS)	2 WATER	3 AIR	4 EXHAUST GASES	5 H_2 (RICH GAS)	6 SLAG	7 NITROGEN
FLOW RATE	tph	325	130	1310	560	60	110	1035
STATE		SOLID	LIQUID	GAS	GAS	GAS	SOLID	GAS
CONC. POLL SOLIDS								
LIQUIDS								
GASES						96% H_2		

FIG. 17 HYDROGEN PRODUCTION

hydrogen sulfide is simply steam stripped in two stages under different pressures releasing hydrogen sulfide in the high pressure stage and ammonia in the low pressure stage. The two hydrogen sulfide rich gas streams are mixed and sent to Claus units for oxidation to elemental sulfur. Tail gases from the Claus units could be treated by means of any of the 15 or so tail gas treatment processes that are available. More on this tail gas treatment will be discussed in a later section.

The ammonia from the second stripper can be recovered as anhydrous liquid and marketed as fertilizer.

Another important emission from any coal liquefaction plant is the particulate matter from the coal handling operation. In the conceptual design this amounts to about 9.2 lb/hr assuming that the control technology is 99.9 per cent efficient. However, as is well known, it is very much dependent upon how the plant is operated and maintained. O & M history and experience (in the USA) does not guarantee that this level of efficiency can be maintained. Even a small reduction in the efficiency of this control technology element, results in several times the rate of emission given above.

Other minor emissions such as hydrocarbons due to spills and the gases from direct fired equipment can be readily controlled by properly designed traps, knock-outs, washers and scrubbing equipment.

5.5.2 Liquid Effluents

The principal liquid effluent is the stripped sour water which still contains dissolved hydrocarbons, inorganic salts and aromatic alcohols. Treatment of these waste waters has been described only vaguely and qualitatively. Even for the pilot plant in which this particular aspect of control technology is to be tested, there are few data available. However, the company, AWARE, Inc., a leader in waste water treatment, is charged with the development of a process for treating these waste waters. A tentative scheme, as described in Section 5.1 has been developed by them, which, will be tested in conjunction with the pilot plant at Catlettsburg, Kentucky.

The proposed concept is to mix all the waste waters, namely stripped sour water, boiler and cooling tower blowdowns, coal pile run-off and other knock-out and accidental spill washes into one stream and treat this stream to meet the standards. The difficulty, however, is in quantifying what is there in all these streams as pollutants and also how to treat them. A simple COD and BOD assessment is insufficient because of the inorganics and heavy metals. Also, the fate of these in the final sludge disposal has to be studied more thoroughly.

5.5.3 Solid Wastes

The main solid wastes resulting from the process are the ash content of the coal, which is produced at a rate of 110 ton/hr in the form of glassy mass from the hydrogen plant, plus a cake from the waste water treatment plant produced at the rate of 40 tons/hr. The disposal of these solid wastes, at the present time, is considered to be only as landfill.

Assuming that there are no harmful leachates resulting from open disposal of these wastes, the full requirement for these quantities is approximately 400 acre-ft per year of operation of the plant. In any case, to be on the safe side, this disposal site must be some sort of lined pond.

5.6 ASSESSMENT

Any control technology assessment has to begin with the efficiency of removal of the harmful substance and the economics of the control technology. The former will be discussed in this section. The latter will be discussed in Section 8.0. The principal control technology systems employed in these commercial coal liquefaction processes are: 1) in the coal handling to remove particulates, 2) tail gas clean-up after the Claus units for H_2S removal, 3) waste waters and their treatment and, 4) handling and disposal of solid wastes. These will be assessed in the following for their efficiencies and efficacies.

5.6.1 Coal Handling and Particulate Control

The control technology as envisaged consists of hooded conveyor belts and handling equipment and air flowing through these hoods passes through a cyclone first to remove the coarse particles and then bag filters for removing the fines. While the cyclones can be designed and operated efficiently for the flow rates involved, the bag filters do present several problems. For instance the air to be handled is approximately 4.2 million SCFM and the filter boxes containing bags to handle such flow rates will be physically staggering. Their operation and mechanical maintenance capability to insure efficiencies greater than 99.9 per cent is questionable. The particulate emission at this efficiency is calculated to be about 9.2 lb/hr and a typical dispersion characteristic of this emission is shown in Figure 18. However, it must be noted that this is based on a removal efficiency of 99.9 per cent. As is well known with these types of systems, it is doubtful that they can be maintained to operate at this efficiency all the time. It is therefore necessary to evaluate their reliability and provide for alternative technologies. An alternative technology is that of wet scrubbing using a venturi scrubber for particulate removal. A discussion of this will be given in Section 7.0 on alternate technologies.

5.6.2 Tail Gas Clean Up

Tail gas from typical Claus plant contains about 2-4 percent of H_2S + SO_2 and up to 10,000 ppm of COS + CS_2. A process usually employed for treating the tail gas is to mix the tail gas with a hydrocarbon fuel such as methane and heat it in a furnace with just enough air to maintain a reducing atmosphere. The SO_2 in the tail gas is reduced to H_2S which adds to the H_2S already present in the tail gas. These gases are then sent for amine wash where the H_2S is absorbed and the clean gases with less than 100 ppm of H_2S are either sent to the boiler furnace or are discharged into the atmosphere.

This technology is proven commercially and is available. The removal efficiencies amount to 99.7 percent and greater. The process can be applied

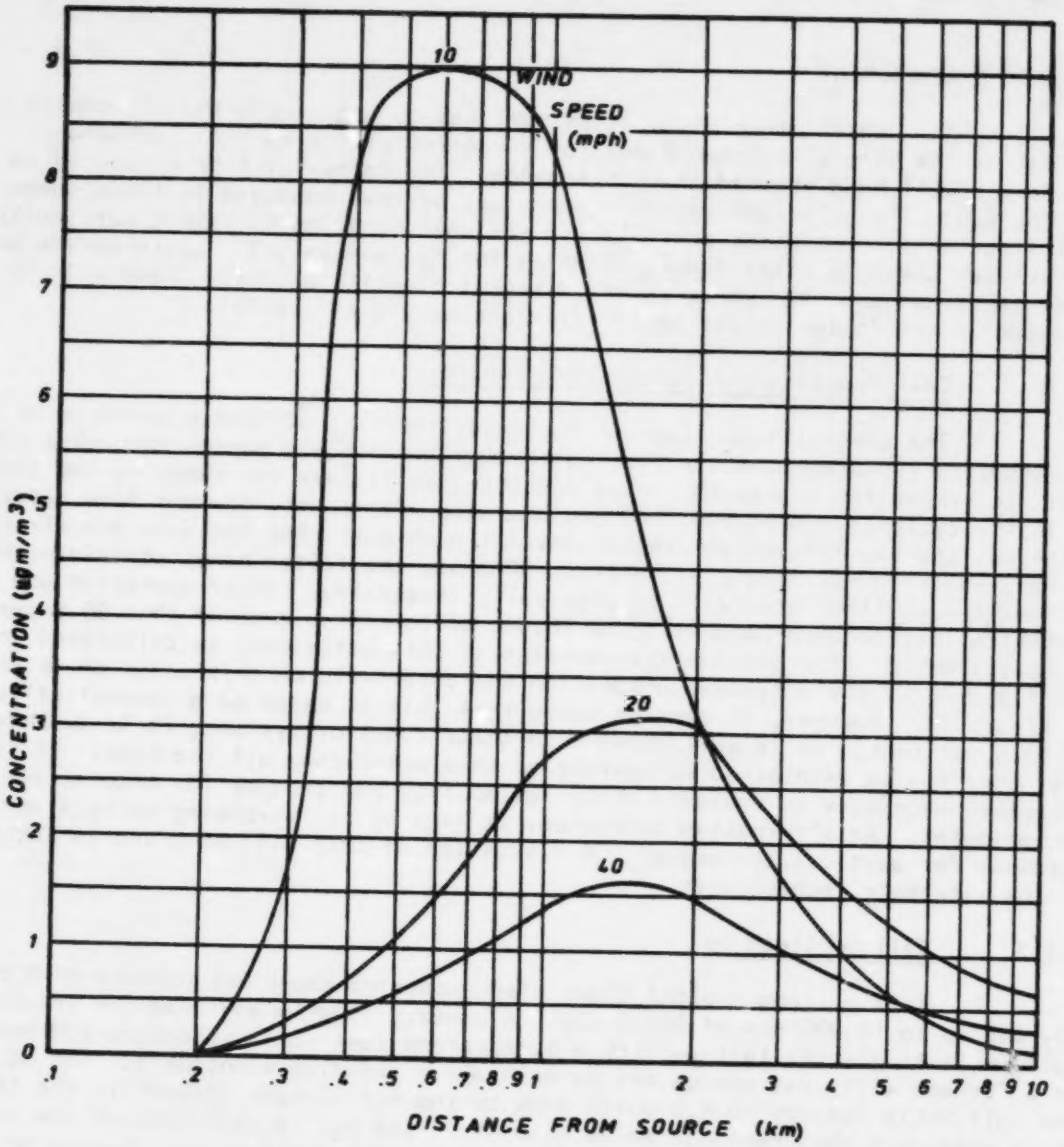


FIG. 18 PARTICULATE CONCENTRATION DISTRIBUTION

anywhere regardless of the local conditions as long as physical space is available.

5.6.3 Waste Water Treatment

This is a technology which is still emerging as far as coal conversion processes are concerned. A great deal of research is now being carried out by the process developers themselves, but as regards control technology, there remain a lot of questions to be answered. Some of the important ones are:

1. What are the amounts and final resting places of the heavy metals present in the coal which find their way into the process waste waters?
2. What poly nuclear aromatics (PNA's) are present and how are they distributed in the final waste waters?
3. The penetration of these pollutants and carcinogens into the ground waters and thus into population groups.
4. Also the adequacy of good clean water around the commercial coal liquefaction plant (CCLP) because the process uses a lot of water in an irrecoverable manner.

These questions cannot be answered at the present time, due to lack of information. So this area of control technology must be emphasized for further study with clearly defined goals.

5.6.4 Solid Waste Disposal

The solid wastes from a CCLP fall into two classes: the regenerable ones such as spent catalyst and the unregenerable wastes containing ash from the coal and various sludges. The regenerable ones are usually shipped out to some processing plant to recover their value. The other type of solid wastes can only be disposed of as landfill at the present time.

Although their chemical character is somewhat different from the common ash from a coal burning plant, the same disposal technology can be used. This consists of ponding within a suitable distance from the plant.

SECTION 6

EVALUATION OF EDS CONTROL TECHNOLOGY

The evaluation procedure for the EDS process control technology follows similar lines to those that are used for the H-Coal process. First, the pilot plant process (the ECLP process) is discussed with respect to all projected plant emissions and the technology that will be utilized to control them. Then an analysis is presented on the appropriateness of the pilot plant emissions control technology. Secondly, a similar discussion will be presented on the commercial-scale EDS process with respect to the plant emissions, the technology utilized to control them and the appropriateness of the control technology. Where possible, the information and judgements gleaned from the discussion of the ECLP process will be applied to the EDS process.

The process itself has been divided into six subsections in such a way that the emissions control problem is of approximately equal gravity in each section. These are: 1) coal handling and preparation, 2) reactions and primary separations, 3) sour gas and sour water treatment, 4) waste water treatment, 5) solid wastes treatment, and 6) catalyst handling.

6.1 EMISSIONS FROM THE PILOT PLANT

In discussing the process emissions for each subsection, Process Systems Diagrams (PSDs) have been utilized, where appropriate, to present process information in a precise and succinct manner .A PSD is formed by combining process steps that form a system with concomitant mass and energy inputs and outputs. Conceptually the system is represented by a rectangular box with necessary input and output streams.

The system boxes may also be considered as modules whose function is identical in the pilot plant and in the commercial plant; only the sizes of the process equipment and streams will vary.

6.1.1 Coal Handling and Preparation

6.1.1.1 Process Description: Coal is delivered to a coal storage area in railroad cars (60 - 100 tons capacity) and then transferred to a 110 ton bottom dump hopper. Through feeders and conveyors the coal is then transferred to a 5000-ton inerted raw coal storage silo (with dimensions of 55 feet diameter and 182 feet high). The coal reception and transfer rate can reach 300 TPH.

The coal preparation plant consists of two parallel equipment trains. These trains begin at the point of collection of the raw coal from the storage silo feeders and proceed through the delivery of the prepared coal to the slurry dryer feeder. One train is designed to crush and dry the coal and deliver it to an inverted coal storage bin. The other train is designed to crush the coal without drying and deliver it directly to the slurry dryer feeder. The preparation plant is located in its own equipment block along with the raw coal storage silo adjacent to the onsite equipment block.

Coal is fed at a rate of 19,960 lbs/hr (239.5 ST/SD) to the ECLP plant. At this stage it has been pulverized to 95 percent minus 8 mesh. Figure 19 is a flow diagram of the coal preparation and storage area.

Emission control equipment is located at various sites in the coal preparation and storage area. The control equipment in place is designed to meet new source performance standards for particulate removal. Table 4 details the atmospheric emissions of the ECLP. Table 5 (source numbers 1 to 5) summarizes the relevant maximum allowable emission rates that appear in the Construction Permit issued to the Carter Oil Company by the Texas Air Control Board. Reference to Figure 19 indicates where the control equipment is located. Table 6 compares the ECLP calculated atmospheric emissions rate with the State of Texas Standards.

6.1.1.2 Sources of Emissions: The following sources of emissions have been identified:

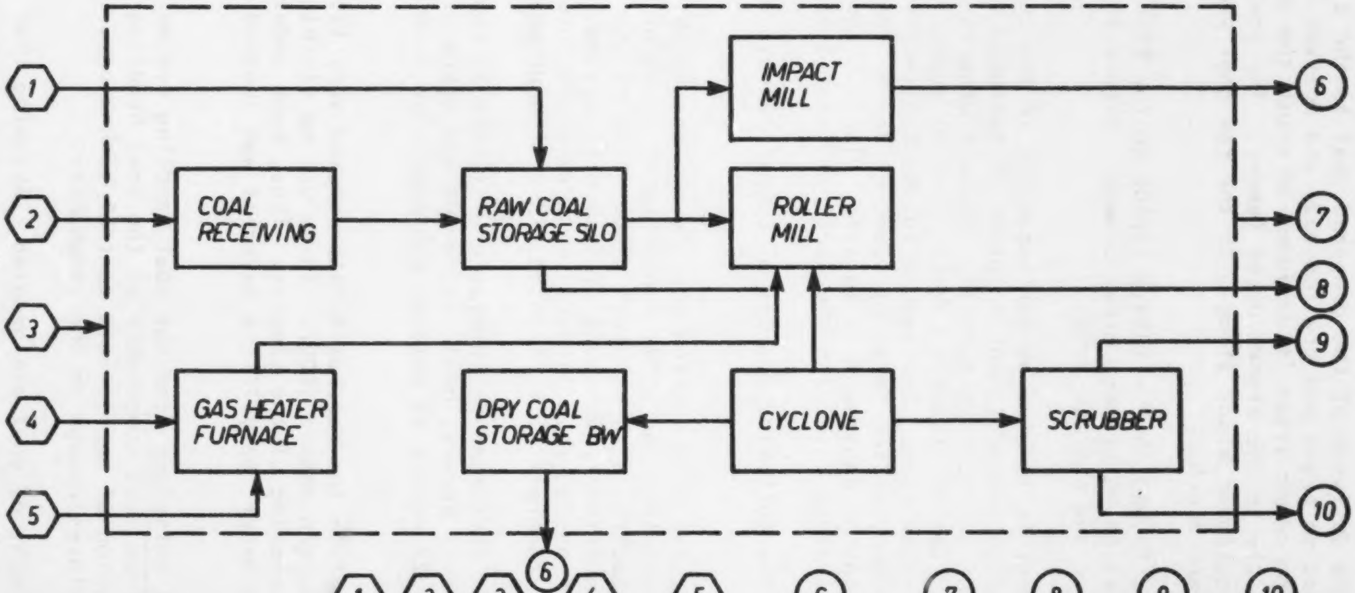
1. Coal Pile runoff results from exposed coal being leached by rainfall. The design calls for the retention of this and other runoff water in an oily water retention tank of 40,000 barrel capacity, with eventual disposition of the oily water in the adjacent Exxon Baytown Refinery Waste Water Treatment System. (See Figure 20). The storm water runoff design rate is based on a rainfall intensity of 3.5 in./hr with a maximum storm rainfall of 10.2 inches in a 24-hour period.

Leaching tests have been performed on samples of Illinois #6 coal in a Weather-O-Meter with exposure to water sprays, heat, infra-red and ultra-violet radiation simulating approximately 27 months of outdoor storage. The results of this test are summarized in Table 7.

Analyses of water taken from the Weather-O-Meter showed very little organic carbon (TOC) or chemical oxygen demand (COD). There was no visible oil in the water nor appearance of weathering of the samples. Thus, even under severe conditions in the Weather-O-Meter, very little material was leached from the coal samples.

2. Particulate or dust emissions from the coal handling system. As mentioned earlier, the emissions from most components of the coal handling system are minimized through the installation of appropriate control technology. However, it is inevitable that some particulates escape to the atmosphere.

Approximately 20,000 lbs/hr of coal are handled. Assuming that 0.3 percent of this is converted into dust in the handling process and a dust collector



1
2
3
4
5
COAL RECEIVING
GAS HEATER FURNACE
RAW COAL STORAGE SILO
DRY COAL STORAGE BW
IMPACT MILL
ROLLER MILL
CYCLONE
SCRUBBER
6
6
7
8
9
10

STREAM / CHARACTER	UNITS	1 RAIN FALL	2 RAW COAL	3 AIR FOR HOODS	4 MAKE UP AIR FOR DRYING	5 FUEL	6 TO PULVERIZED DRYING AND LIQUIFACTION SECTION	7 AIR FROM DUST COLLECTORS	8 COAL STORAGE RUNOFF	9 VENTED AIR FROM SCRUBBER	10 SCRUBBER LIQUID EFFLUENT
FLOW RATE	LBS/HR		19,960								
STATE		LIQ.	SOLID	GAS	GAS	GAS	SOLID	GAS	LIQUID	GAS	LIQUID
CONC. POLLUT.											
SOLIDS	mg/ltr							0.06*			
LIQUIDS	mg/ltr										
GASES	ppm										

*LBS/HR.

FIG. 19 FLOW DIAGRAM OF COAL PREPARATION AND STORAGE AREA: ECLP PLANT

TABLE 4

ECLP ATMOSPHERIC EMISSIONS (15)

Sources	Heat Fired (10^6 Btu/hr)	Stack Height (ft.)	Stack Diameter (inches)	Exit Gas Temp. (°F)	Gas[a] Flowrate (SCFM)	Emission Rates (lbs/hr) SO_2	NO_x	NMHC	TSP	CO
Liquid Recycle Gas Preheat	9.10	95	22	584	2170	0.13	1.03	0.22	0.91	0.19
Liquid Slurry Preheat (1 & 2)[b]	25.20	88	33	1270	3010[c]	0.36	2.85	0.60	2.53	0.53[d]
Vacuum Stripper Feed	3.60	68	21	1400	860	0.05	0.41	0.09	0.36	0.08
Solvent Hydrogenation Reactor Preheat	9.16	90	22	625	2190	0.13	1.04	0.22	0.92	0.20
Solvent Fractionator Preheat	9.28	86	24	710	2220	0.13	1.05	0.22	0.93	0.20
Fugitive Losses (Tankage, Valves, Seals, etc.)						-	-	3.75	-	-

[a] At 60°, 14.7 psia

[b] Only one liquid slurry preheat furnace operates at one time. Each furnace has two identical stacks.

[c] Per stack

[d] Total for both stacks.

TABLE 5

MAXIMUM ALLOWABLE EMISSION RATES FOR COAL PREPARATION AND HANDLING FACILITIES IN THE ECLP (16)

Source Number	Source Name	Emission Rate SO_2 lbs/hr	Emission Rate SO_2 T/year
01	Fugitive Coal Dust at Rail Car Dump Site[a]	4.0	6.0
02	Coal Unloading Pit Bag Filter Effluent[a]	0.3	0.1
03	Coal Receipt Bag Filter Effluent[a]	2.1	0.2
04	Coal Preparation Bag Filter Effluent	0.6	1.4
05	Coal Preparation Venturi Scrubber Effluent Gas	3.5	9.2
06	Vacuum Bottoms Venturi Scrubber Effluent Gas	0.3	0.7
07	Vacuum Bottoms Conveyor Discharge Bag Filter	0.5	1.3

[a] The lb/hour rate applies to an operating schedule of 10 hours/day.

TABLE 6

COMPARISON OF CALCULATED ECLP ATMOSPHERIC EMISSIONS AND STATE OF TEXAS STANDARDS (17)

SOURCE #	SOURCE NAME	EMISSION RATES (LBS/HR)					
		SO_2		NO_x		NMHC	
		CALCULATED	MAR[a]	CALCULATED	MAR	CALCULATED	MAR
1	Liquid Recycle Gas Preheat	0.13	NV[b]	1.03	NV	0.22	NV
2	Liquid Slurry Preheat	0.36	1.0	2.85	4.2	0.60	0.8
3	Vacuum Stripper Feed	0.05	0.2	0.41	0.9	0.09	0.1
4	Solvent Hyrogenation Reactor Preheat	0.13	0.3	1.04	1.9	0.22	0.2
5	Solvent Fractionator Preheat	0.13	0.3	1.05	1.9	0.22	0.2
6	Fugitive Losses					3.75	28.8

a. MAR: Maximum Allowable Rate
b. NV: No Value Available

TABLE 6 . (Continued)

SOURCE #	SOURCE NAME	EMISSION RATES (LBS/HR)				EMISSION CONCENTRATIONS (ppm)	
		TSP		CO		SO_2	
		CALCULATED	MAR	CALCULATED	MAR	CALCULATED	STANDARD
1	Liquid Recycle Gas Preheat	0.91	NV	0.19	NV	6	440
2	Liquid Slurry Preheat	2.53	3.1	0.53	0.6	6	440
3	Vacuum Stripper Feed	0.36	0.5	0.08	0.1	6	440
4	Solvent Hyrogenation Reactor Preheat	0.92	0.9	0.20	0.2	6	440
5	Solvent Fractionator Preheat	0.93	0.9	0.20	0.2	6	440
6	Fugitive Losses						

a. MAR: Maximum Allowable Rate
b. NV: No Value Available

TABLE 7

WEATHER-O-METER LEACHING TESTS FOR THE LIQUEFACTION BOTTOMS AND ILLINOIS #6 COAL USED IN THE ECLP (18)

Weight Loss: After 27 days (equivalent to 27 months outdoor exposure)

Liquefaction Bottoms -	Weight Before-------	556.7 grams
	Weight After -------	556.2
	Loss -------	0.5 grams
Illinois No. 6 Coal	Weight Before-------	463.1 grams
	Weight After -------	417.2
	Loss -------	45.9 grams

No weathering of either Liquefaction Bottoms or Coal was apparent by visual inspection.

Analyses of Water Taken from Weather-O-Meter:

Sample	Water After Day	TOC	TOD	COD	BOD
Liquefaction Bottoms	4	29	34	79.7	1.8
	11	14.5		56.4	1
	14	13		0	1
	18	16	3	5.1	1
	21	16		6.7	1
	27	16.5		7.9	1
Illinois No. 6 Coal	4	29.5	39.4	69.7	1.7
	11	16.5		56.6	1
	14	18.5		18.2	1
	18	18.5	4	16.1	1
	21	16.0		10.5	1
	27	15.5		5.9	1
Distilled Water Source		6	3		
Distilled Water From Weather-O-Meter with Blank Sample		12	3		

TOC = Total Organic Carbon
TOD = Total Oxygen Demand
COD = Chemical Oxygen Demand
BOD = Biological Oxygen Demand

efficiency of 99.9 percent the final emission rate will be

$$20{,}000 \times \frac{0.3}{100} (1-0.999) = 0.06 \text{ lb/hr}$$

Pressurized blowdown streams from the venturi scrubbers in the coal preparation are handled separately and sent directly to the Baytown Refinery cat-cracking unit scrubber settling pond where their fines (5 weight percent maximum) will settle out.

3. The exact fuel gas composition used to heat the air in the gas heater furnace is unspecified. However, its characteristics are identical to the fuels used by the furnaces in the process block where current EPA standards for fossil fuel firm steam generators are easily met (See Table 8).

6.1.2 Reactions and Primary Separations

6.1.2.1 Process Description: Subsections 4.2.1 through 4.2.5 provide a concise description of the reactions and primary separations as they are handled in the ECLP with the following modifications:

i) There is no flexicoker stage, thus there is no autogenous source of low-Btu gas (LBG). The ECLP produces 1,340 lbs/hr of fuel gas of unspecified heating content (See Figure 7). Supplementary fuel gas needs are met through the purchase of natural gas from local utility companies.

ii) Similarly, there is no possibility of generating hydrogen through the steam reforming of the methane/ethane gas that would be produced in the flexicoker section. Some of the hydrogen process needs are met through the cryogenic purification of purge gas; however most of the process hydrogen is supplied by the adjoining Baytown Refinery.

6.1.2.2 Sources of Emissions: Both continuous and fugitive emissions are generated from this section of the process as well as gaseous and solid effluent streams. The principal continuous emissions are:

Effluent Name	Quantity	Comments
Solids Residue	7,890 lb/hr (0.394 lbs/lb of coal feed)	Contains ash, unconverted carbon, heavy hydrocarbons
Waste Gases	1,590 lbs/hr (0.08 lbs/lb of coal feed)	Contains 176 lbs of sulfur/hr
Sour Water	23,690 lbs/hr (1.185 lbs/lb of coal feed)	Contains equilibrium amounts of hydrogen sulfide, ammonia, carbon dioxide plus phenolics and polynuclear aromatics

TABLE 8

COMPARISON OF ECLP ATMOSPHERIC EMISSIONS AND FEDERAL STANDARDS (19)[a]

Emission Source	SO_2 (lb/10^6Btu)	Standard (lb/10^6Btu)	TSP (lb/10^6Btu)	Standard (lb/10^6Btu)	NO_x (lb/10^6Btu)	Standard (lb/10^6Btu)
Liquid Recycle Gas Preheat	0.01	1.2(solid fuel) 0.8(liquid fuel)	0.10	0.1	0.11	0.7(solid fuel) 0.3(liquid fuel) 0.2(gas fuel)
Liquid Slurry Preheat	0.01	"	0.10	0.1	0.11	"
Vacuum Stripper	0.01	"	0.10	0.1	0.11	"
Solvent Hydrogenation Reactor Preheat	0.01	"	0.10	0.1	0.11	"
Solvent Fractionator Preheat	0.01	"	0.10	0.1	0.11	"

---

[a] 40 CRF 60. There are no federal standards of performance applicable to the ECLP project. The standards listed are those for fossil-fuel fired steam generators with a heat input more than 250 million Btu per hour.

Table 6 indicated the levels of expected fugitive emissions from the ECLP. Table 9 gives a detailed rundown of the ECLP sour water sources. (23,690 lbs/hr of water flow are equivalent to 47.4 gpm).

6.1.3 Sour Water and Gas Treatment

6.1.3.1 Process Description: The ECLP sour water contaminants of most concern are carried by the sour water streams of the process block. These sour water streams are individually listed with their expected rates in Table 9. The maximum total sour water rates are approximately 52 gpm for the Illinois coal operation and 61 gpm for the Wyoming coal operation. From the ECLP sour water collection drum, the sour water is sent to the Baytown Refinery for treatment in existing sour water handling facilities. A one hour storage hold for the sour water is provided to permit continued operation of the coal plant during short-term interruptions of sour water flow to the refinery. Treatment at the refinery consists of steam stripping contaminants from the water. The removed contaminants (mainly H_2S, NH_3, and CO_2) are then sent to the refinery's Claus sulfur plants where they are partially oxidized.

The stripped sour water is sent to crude desalters in the Baytown Refinery and subsequently combined with other waste waters for future processing at the waste water treatment plant.

The sour gases in the ECLP consist of separate hydrogen and fuel gas streams. Each stream is compressed, water washed and DEA scrubbed for removal of H_2S and NH_3. The H_2S and CO_2 are stripped from the DEA in the regenerator feed, water washed for NH_3 removal and subsequently sent to Claus units for partial oxidation at the adjacent refinery. It should be noted that the fuel gas treating section alone has the capacity to process 1.75 million SCF/SD of feed.

6.1.3.2 Sources of Emissions: Since the ECLP sour waters and the off gases from the regenerator towers are sent directly to the Baytown Refinery for subsequent treatment, no emissions will be produced in the sour water and gas treatment of the ECLP systems. However, the presence of polynuclear aromatics (PNA's) in the stripped sour water are of some concern. The amount of polynuclear aromatics are based on Wyoming Wyodak coal which produces about 15 times the amount from Illinois coal. The planned testing program calls for running Wyoming Wyodak coal for only about 6 months out of the projected 2.5 year program. The Wyodak operation would contribute only 2 to 3 parts per billion of PNA's to the refinery's untreated waste water (10-12,000 gpm).

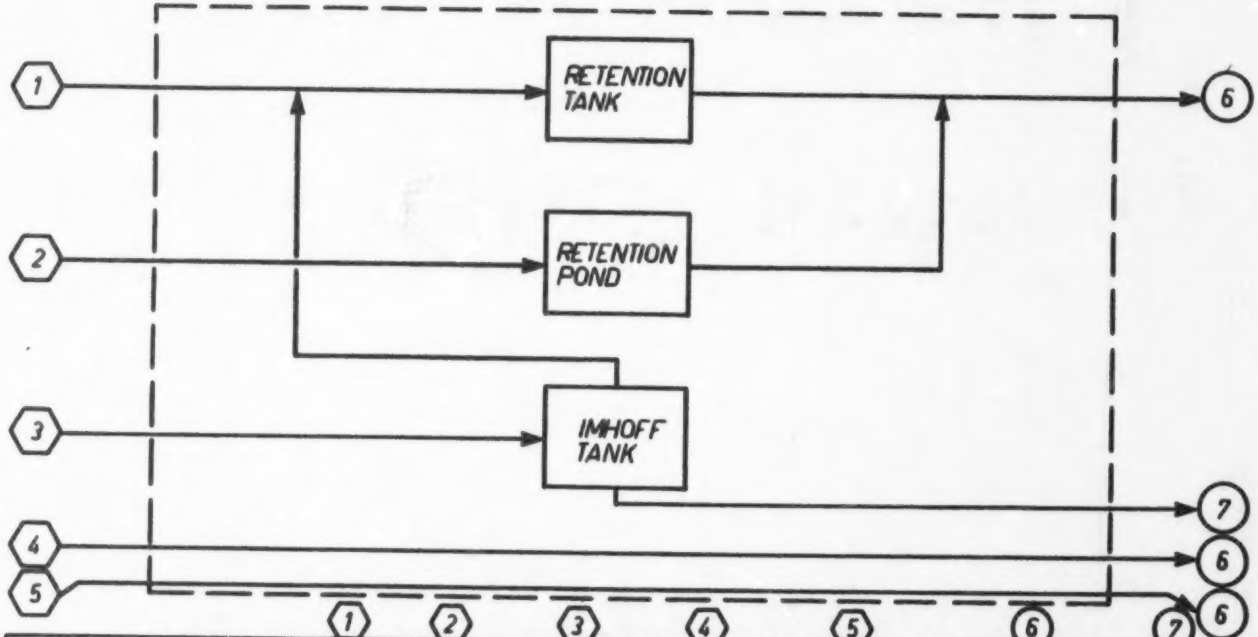
The subsequent effect of stripping the sour water (in the crude desalters) of phenolics and PNA's has not been quantified.

6.1.4 Waste Water Treatment

6.1.4.1 Process Description: The waste treating facilities collect, store, and dispose of all waste water streams from the Exxon Coal Liquefaction Pilot Plant. A diagram of sources and dispositions is shown in Figure 20. The waste treating facilities have been specified on the basis of segregating waste streams into oily water, non-oily water, and sanitary wastes.

TABLE 9
ECLP SOUR WATER SOURCES (20)
EDS PROCESS

Source	Rate, GPM Illinois	Rate, GPM Wyodak
Phenolic water		
Slurry dryer distillate drum	5.3	13.0
Liquefaction cold separator	4.7	5.6
Atm. frac. distillate drum	2.4	2.4
Vacuum stripper distillate drum	11.7	11.7
Solvent hydro. cold separator	5.3	5.3
Solvent frac. distillate drum	1.7	1.7
Subtotal	31.1	39.7
Nonphenolic water		
Liquefaction recycle gas scrubber	2.0	2.0
Solvent hydro. recycle gas scrubber	2.8	2.8
Fuel gas scrubber	8.4	8.4
Fuel gas condensate separator drum	0.1	0.1
Acid gas scrubber	3.0	3.0
Flare seal drum	5.0	5.0
Subtotal	21.3	21.3
+ TOTAL	52.4	61.0


1
2
3
4
5
RETENTION TANK
RETENTION POND
IMHOFF TANK
6
7
6
6
7

STREAM / CHARACTER	UNITS	1 OILY STREAMS	2 NON OILY STREAMS	3 PROCESS BLOCK SOUR AND PHENOLIC WATERS	4 SANITARY WATERS	5 COAL PREPARATION AND VACUUM BOTTOMS SCRUBBER WATER	6 TO REFINERY WASTEWATER TREATMENT SYSTEM	7 SLUDGE TO SCAVENGER
FLOW RATE	GPM			80		30	540	
CONC. POLLUT.								
BOD								
COD								
TOC								

FIG. 20 WASTEWATER SOURCES IN THE ECLP PLANT

Other waste water streams without treatment facilities within the plant include sour waters from the process block, coal preparation water and vacuum bottoms scrubber water, all of which are sent directly to the Baytown Refinery. Uncontaminated rain water runoff flows to the natural drainage.

The oily water sewer system collects all waste water streams that might be expected to be contaminated with oil. These streams include process oily wastes, tank/drum water drawoff, tankage area runoff, safety area runoff, storm runoff from oil contaminated process areas and pump pads, cooling tower blowdown, excess collected condensate, and any other miscellaneous oil water streams. The collected oily water is pumped to the retention tank from where it is gradually pumped to the refinery's waste water treating facilities.

The non-oily water sewer system collects all waste water streams that might contain coal fines and other oil-free streams. These streams include 1) storm runoffs from the coal preparation and vacuum bottoms cooling and loading areas, and 2) coal unloading sump water. The collected non-oily water is pumped to the retention pond where provisions for fines settling have been made. The pond effluent is pumped intermittently to the refinery for treatment in their waste water treatment system.

The sanitary sewer system collects sanitary wastes from the control house, general purpose building, coal unloading shed, and the administration building. Sanitary sewage is treated in an Imhoff tank and the tank effluent sent to the oily water retention tank. The Imhoff tank effluent is chlorinated to residual level of one milligram per liter.

Rainwater runoff from tank and drum fields is considered to have some oil contamination and is contained within the fire banks. The contained runoff is discharged at a controlled rate to the oily water collection system during dry periods. Oily and sanitary sludges collected in the treated waste facilities are removed by vacuum truck.

Pressurized blowdown streams from the venturi scrubbers in the coal preparation and vacuum bottoms solidification areas are handled separately and sent directly to the refinery's fluid cat-cracking unit scrubber settling pond where the fines content (5 wt percent maximum) will settle out. The clarified water from this pond is sent to the refinery waste water system. Disposal of the settled fines will be handled by the refinery, along with the settled catalyst fines.

Uncontaminated clean rainwater runoff from areas such as parking lots will be directed toward the natural drainage that now characterizes the proposed plant site.

6.1.4.2 Sources of Emissions: Since all the waste treatment will take place off site at the Baytown Refinery there will be no emissions generated at the ECLP. As a result, there are no wastewater emissions to describe.

6.1.5 Solid Wastes Treatment

6.1.5.1 Process Description: The bottoms product from the vacuum stripper tower will be solidified and disposed of in an approved landfill. Two lines feed the liquid product from the vacuum tower into two distributor nozzles which spread the liquid across the width of a steel-belted cooling conveyor. The liquid cools and solidifies on the steel belt into a sheet approximately 1/4" thick. The solidification is accomplished by spraying cooling water on the underside of the cooling belt. The bottoms product solidifies into a brittle sheet which breaks into small pieces as it discharges from the end of the cooling conveyor. The material then falls through a chute onto a conventional, portable conveyor which elevates the material and discharges it into portable steel containers. The material is hauled away in these containers and disposed of in a landfill. Figure 21 is a diagram of the solid waste handling procedure. The bottoms production rate is 7890 lbs/hr.

6.1.5.2 Sources of Emissions: The vacuum bottoms slurry contains ash, uncovered coal and heavy hydrocarbons. It also generates a fume consisting of a fine liquid aerosol which is made up of hydrocarbons. The aerosol does not contain gases such as SO_2, H_2S, CO or NO_x. Design values from the heat and material balance indicate that the lightest component of the vacuum bottoms is a hydrocarbon with a boiling point of 760°F.

The fumes from the cooling belt are completely withdrawn and sent through a high-energy venturi scrubber. In addition, the discharge end of the conveyor, where the solidified bottoms are loaded into transport conveyors, is enclosed with a hood which sends fines-containing vapor through a bag filter (See Figure 21.) Source numbers 6 and 7 of Table 4 outline the maximum allowable particulate matter emission rates for this equipment.

The solidifed vacuum bottoms will be hauled by a waste disposal company to a landfill site. At the landfill site, the disposal pit is impervious clay from which there is no runoff and little or no seepage. Leaching tests have been performed on vacuum bottoms samples in a Weather-O-Meter with exposure to water sprays, heat, infra-red and ultraviolet radiation simulating approximately 27 months of outdoor storage. The results of this test are summarized in Table 7. Weight loss from the bottoms sample are neglible (less than 0.1 percent) and less than that observed in similar tests with the parent coal. Analyses of water taken from the Weather-O-Meter showed very little organic carbon (TOC) or chemical oxygen demand (COD). There was no visible oil in the water, no appearance of weathering of samples. Thus, even under severe conditions in the Weather-O-Meter, very little material was leached from the vacuum bottoms. Even less leaching is expected under the milder conditions in a buried landfill, and any that should occur will be retained in the impervious pit.

Other solid waste sources have much lower volumes and require intermittent disposal. Among them are the following:

1. A non-oily water retention pond gradually builds up an accumulation of coal fines which settle to the bottom of the pond. When a level of approximately

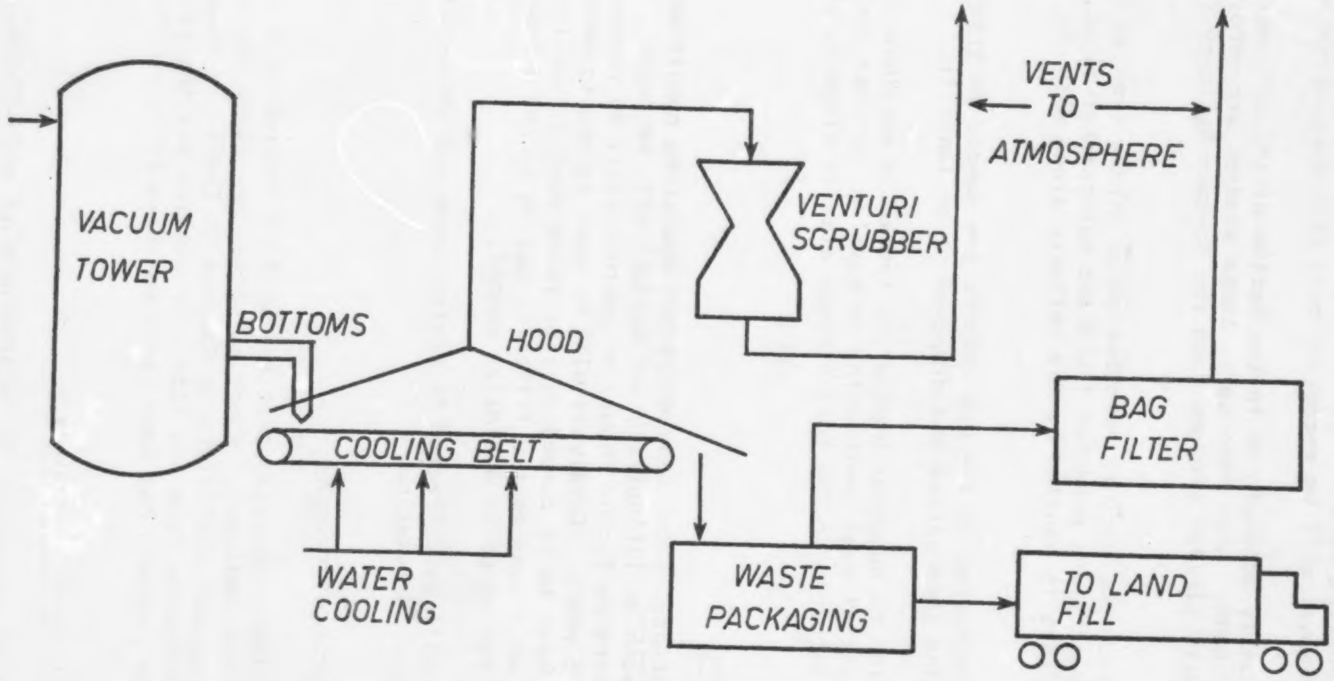

VACUUM TOWER
BOTTOMS
HOOD
COOLING BELT
WATER COOLING
VENTURI SCRUBBER
VENTS TO ATMOSPHERE
BAG FILTER
WASTE PACKAGING
TO LAND FILL

FIG.21 DISPOSAL OF ECLP VACUUM TOWER BOTTOMS[1]

[1] FLOW RATE: 7890 LBS/HR OR 94.7 ST/SD.

six inches has accumulated in the shallow section of the pond, the layer is bulldozed to the coal-fines collection sump on the eastern end of the pond. Evacuation then will be to a state authorized landfill site. Over the short project life, it is unlikely that fines removal will be necessary more than once or twice.

2. Sludge eventually accumulates in the bottom of the oily water retention tank and the Imhoff tank. When necessary, these sludges are removed by vacuum truck and combined with similar sludges from the Baytown Refinery for disposal.

3. Coal fines from the venturi scrubber purge stream eventually settle out in the Baytown Refinery settling pond for fluidized cat-cracker fines. Disposal of the settled coal fines is handled by the refinery along with the settled catalyst fines.

4. Coal fines collected in the bag filters are dumped to grade-level "tote bins" for disposal, and then wetted and disposed of as landfill.

5. Coal diversion to dumpster bins or to trucks is possible in the coal preparation area in the event of coal overheating or burning, or when testing the system. Diverted coal is returned to the coal storage area or disposed of to a state approved landfill.

6.1.6 Catalyst Handling

6.1.6.1 Process Description: Since many different operating conditions and different types of coal (such as Illinois #6 and Wyodak) will be tested, it is estimated that the plant service factor should be approximately 60 percent during the operating period of 2.5 years. Catalysts will be used in the solvent hydrogenation reactors and may have to be dumped once or twice during the life of the project. Spent catalyst, when used as the filtering medium in the solvent hydrogenation feed filter is disposed of in a similar manner.

Spent catalyst will be collected in sealed drums and shipped to a firm on the Gulf Coast for metals reclamation.

6.2 PILOT PLANT CONTROL TECHNOLOGY

It has already been indicated that the ECLP is located on a site adjacent to the Exxon Baytown Refinery. Where possible, advantage has been taken of the available waste treatment facilities at Baytown to treat the gaseous liquid and solid waste streams emanating from the ECLP. In section 6.1 the treatment and disposal of the ECLP waste products has been reviewed--here it is presented in a more concise fashion.

6.2.1 Air Emissions Control Technology

Emissions control technology is located on-site and offsite of the ECLP. On-site control technology is located in the following areas; a) coal preparation and storage; b) various fractional and preheat furnaces; c) solid waste handling and d) pretreatment of sour gases. Further treatment of the fuel gas takes place offsite at the Baytown Refinery.

The performance of the required control equipment mandated to be in place (that principally consists of different bag filters) at the coal preparation and storage areas is summarized in Table 5. Similar performance data on the various furnace emissions appears in Table 6. The furnace fuels are selected to comply with Federal New Source Performance Standards for Fossil Fueled Steam Generators while the furnace stack heights are designed to comply with Regulation I, Rule 105.12 and Regulation II, Rule 201.012 of the Texas Air Control Board.

The performance requirements of the emission control equipment that will be in place in the solid waste handling area are outlined in Table 5. (See also Figure 21 and Section 6.1.5.2). As previously indicated (in Section 6.1.3.1) the sour gases are compressed, water washed and DEA scrubbed for removal of hydrogen sulfide, ammonia and carbon dioxide. The hydrogen sulfide and carbon dioxide are subsequently stripped from the DEA in the generator feed and water washed for ammonia removal.

The resulting hydrogen sulfide/carbon dioxide gas mixture is forwarded to the Baytown Refinery for conversion into sulfur in a Claus unit. A tail gas cleanup unit is provided to reduce the sulfur content of the sulfur plant tail gas to an acceptable environmental level. Approximately 99.9 percent of the sulfur plant feed sulfur is recovered while the tail gas cleanup unit reduces sulfur dioxide emission to about 100 ppm.

6.2.2 Liquid Effluents Control Technology

A full description of the on-site facilities for the collection and storage of the waste water streams is given in Sections 6.1.3.1 and 6.1.4.1. Eventually all the ECLP generated waste waters are transferred to the Baytown Refinery and treated in the waste water system there.

The Baytown Refinery waste water treatment system has permits (both federal and state) to discharge its treated waste waters into the Houston Ship Canal. Since the maximum possible flow of ECLP waste waters is less than 3 percent of the design capacity of the Baytown Refinery Waste Water Treatment System a judgment was made by the Texas Department of Water Resources that no new discharge permit was needed in this case.

6.2.3 Solid Waste Control Technology

All solid wastes are collected and disposed of in a state approved landfill site. Full details of these operations are available in Sections 6.1.5.2 and 6.1.6.1. Leaching tests were also carried out on the vacuum bottom samples and showed a neglible weight loss and very little chemical oxygen demand (COD). Further details of the leaching tests are provided in Section 6.1.5.2.

6.2.4 Environmental Testing Program

The overall objectives of the Environmental Testing Program are twofold:

1. A quantitative assessment of the environmental impact of the EDS plant and
2. Evaluation of control techniques used to comply with environmental regulations in a cost-effective manner.

Major emphasis will be placed on resolving the liquid effluent problem, specifically:

a) Waste water streams will be characterized as process modifications are made.

b) Treatability studies will be carried out with liquefaction-coking waste waters to test the efficacy of solvent extraction, BIOX and activated carbon.

c) An evaluation will be made of existing and emerging environmental control technology and research and development needs for new environmental control technology.

d) A pilot waste water treatment plant will be designed, constructed and operated to treat a slipstream of the ECLP waste waters.

e) It is expected that preliminary design studies for evaluation of alternative waste water treatment techniques for the EDS process will be completed.

Air emissions studies incorporate the following features:

a) Quantitative characterization of the various emissions from laboratory pilot units.

b) Assessment and evaluation of methods for fugitive dust problems.

c) Assessment of the environmental impact of burning synthetic fuel plant streams (i.e., heavy liquids, low-Btu gas) in on-site furnaces and boilers.

d) Evaluation of noise and control techniques for liquefaction plant equipment not common to refineries or chemical plants (e.g., large scale coal crushing and transportation).

In all cases, consideration will be given to potential changes that can be made in the EDS process to minimize water and atmospheric emissions, while taking into account the evolving status of federal and state environmental regulations.

6.3 ANALYSIS OF THE PILOT PLANT CONTROL TECHNOLOGY

The primary objective of Exxon Research Engineering Company in setting up the ECLP is the development to commercial readiness of a Donor Solvent process for coal liquefaction. While a lot of work has and will be done in the monitoring and control of pollutants, it is obvious that the pollution control problem has a lower priority, especially since the ECLP scrubber product gases and all waste waters are sent to the Baytown Refinery for subsequent treatment. This approach has minimized the consideration of engineering controls as pilot plant process modification that could be instrumental in eliminating the generation of pollutants at the source.

Within the context of treating the incorporation of control technology as an "end of pipe" requirement rather than as an integral part of the process itself a strong development program is underway in the areas of waste water treatment and air emission control (see Section 6.2.4). However, there is no published evidence that indicates that the full ramifications of the Resource Conservation and Recovery Act of 1976 have been noted or are being acted upon, especially with respect to Sections 3001-3005 of the Act that treat the identification of hazardous wastes and sludges, the promulgation of guidelines and regulations that affect the generation, treatment, transportation, storage of hazardous wastes, and their concomitant handling facilities.

It bears noting that no plans have been made for predicting how the ECLP control equipment will function under unsteady state conditions. Since the ECLP is an experimental plant that will be operated under varying feed compositions and operating conditions it is inevitable that for a large proportion of its operating life unsteady state conditions will prevail.

An important topic that has not been addressed, even superficially, is the question of the interference/inhibition effects of toxic organic chemicals (such as phenols) or heavy metals (such as chromium from the cooling tower blowdown) on the biological part of the waste water treatment process at the neighboring Baytown Refinery. For example, concentrations as low as 0.02 mg/l of phenols have been reported to be capable of upsetting secondary waste water treatment plants. An even more insidious problem is the question of dealing with slug flows of such toxic organic chemicals and heavy metals.

Finally, it should be noted that a much more thorough analysis of the control of pollutants from the ECLP process is needed to ensure that the development of the coal liquefaction is completely consonant with the public health and welfare as reflected in the Clear Air Act (1977), the Clean Water Act (1977), the Resource Conservation and Recovery Act (1976), and the Toxic Substances Control Act (1976). At the very minimum the following information should be made available:

1. A detailed mass balance giving inlet and outlet stream characteristics (flow and composition) for the major process stages such as coal storage and preparation, coal liquefaction, solvent hydrogenation, etc.

2. The fuel gas composition and its variation with changes in the process operating parameters such as the solvent-coal ratio.

3. A detailed breakdown of the sour water composition (both ionic and organic) especially with respect to concentrations of heavy metals and polynuclear aromatics and its variation with respect to changes in the process operating parameters.

4. The dimensions of the proposed air pollution control equipment and the design air flow rates.

6.4 EMISSIONS FROM THE COMMERCIAL PLANT

6.4.1 Coal Handling and Preparation

6.4.1.1 Process Description: Coal will be received five days per week from two mines at a total rate of 34,000 TPD. The run-of-mine (ROM) coal will be brought in from the distant mine by an 85-car train (2 trains/day), and from the nearby mine by conveyor belt (constant service).

A common conveyor will be utilized to transfer coal from the incoming nearby mine conveyor and coal received via railcar unloading facilities to the stacker-reclaimer area (live storage). If the reclaimer is out of service, coal from the live storage piles will be transferred by mobile equipment to a dump hopper on the conveyor feeding the crushers. Similarly, dead storage can be reclaimed by mobile equipment and dumped into the dump hopper and then moved through the plant in the normal fashion.

The incoming coal will be stored in two stockpiles with a combined storage capacity of 10 days of process feed. Two tripperstackers will be used to stack the live storage piles at a rate up to 4,000 TPH. A 30-day dead storage pile will be built up and retained.

A crawler-mounted reclaimer will be used to reclaim the stored coal (24 hr/day, 7 days/week) at rates varying from 1,000 to 1,500 TPH. A surge storage silo with a capacity of four hours of process feed will be provided downstream of the stock piles. This will eliminate flow-rate surges and allow up to four hour equipment stoppages upstream of it without affecting process feed to the liquefactor trains.

Three 50 percent crushers (500 TPH each) will be provided downstream of the surge silo. The crushers will reduce the reclaimed ROM coal from 90 percent minus 1 inch to 95 percent minus 8 mesh. The crushed coal will then be elevated in enclosed belt conveyors to a distribution bin which divides the total flow of crushed coal into 8 streams to feed the 4 dryers. Eight gravimetric feeders (2/slurry dryer) will be located directly under the distribution bin to control feed to the slurry dryers.

The following steps are taken in the design to minimize emissions from the coal handling and preparation area:

1. Water sprays are provided at the track hopper pit to suppress the dusting resulting from bottom-dumping of coal from railroad cars.
2. Water sprays are also utilized at the outlets of the coal crushers.
3. The inclined conveyor belts from the crushers to the feed distributing bins are housed in a completely enclosed gallery with emissions controlled by baghouse filters.
4. Each transfer point along the covered conveyor belts also has a baghouse filter to remove particulates and dust.

A major difference in the ECLP and EDS processes is that the option of crushing *and* drying the coal before delivering it to the slurry dryers is not available for the EDS process. Also, at this time emissions in the coal handling and preparation area have *not* been quantified *nor* have the costs of the associated pollution equipment been detailed explicity.

6.4.1.2 Sources of Emissions: The sources of emissions are as follows:

1. The coal pile runoff results from exposed coal being leached by rainfall. The design calls for the retention of this and other runoff water (containing fines) in a rainfall retention pond of 22 million gallon capacity with eventual disposition of the rainwater in the EDS waste water treatment system.

2. Particulate and dust emission from the coal handling system will be appreciable in spite of the installation of appropriate control technology. Approximately 1000 tons/hr (2×10^6 lbs/hr) of coal are handled. Assuming that 0.3 percent of this is converted into dust in the handling process and a dust collector efficiency of 99.9 percent the final emission rate will be:

$$2 \times 10^6 \times \frac{0.3}{100} (1-0.999) = 6 \text{ lb/hr}$$

6.4.2 Reactions and Primary Separations

6.4.2.1 Process Description: Subsections 4.2.1 through 4.2.7 provide a concise description of the reactions and primary separations as handled by the EDS process.

6.4.2.2 Sources of Emissions: Both continuous and fugitive emissions are generated from this section of the process. The principal continuous emissions are:

EFFLUENT	QUANTITY	COMMENTS
Solids residue	2780 ST/D	Consists of ash residue, these flexicoker emanating solids are sent to a (5 year capacity) settling pond.
Air emissions	See Table 10	Consists of principally of furnace emissions.
Effluent water	7000 GPM	Contains oils, phenols, hydrogen sulfide, ammonia; consult Table 11.

The dry fines from the flexicoker are pneumatically conveyed to offsite mixing tanks. These dry fines are removed in a venturi scrubber prior to releasing the carrier air to the atmosphere. A very small but undetermined amount of dry fines is emitted to the atmosphere along with this air. An H_2S removal unit removes H_2S from the low-Btu fuel gas from the flexicoker.

6.4.3 Sour Water and Gas Treatment

6.4.3.1 Process Description: The EDS sour water and sour gas treatment trains are more comprehensive than the corresponding trains in the ECLP process; not only do they allow for the recovery of sulfur, but they also recover ammonia and phenolics as well. Conveniently, the sour water and sour gas treatment facilities can be divided into five sections:

i) Sour water treating
ii) Ammonia recovery
iii) Phenolic water treating
iv) DEA regeneration
v) Sulfur plant and tailgas cleanup

A process flow diagram for the gas and water treating facilities is given in Figure 22.

- Sour Water Treating

Sour water treating consists of facilities for stripping H_2S, CO_2 and NH_3 from the sour water. A H_2S and CO_2 stream is fed to the sulfur plant for recovery of elemental sulfur, while the ammonia is recovered as a high purity anhydrous product. The plant contains two-50 percent sour water strippers, each designed to handle 860 gpm of sour water from a single liquefaction train. Intermediate tankage is provided to handle up to 6 days of sour water production from a single liquefaction train in the event that the sour water stripper is out of service. The sour water contains 3000-4000 ppm of phenols.

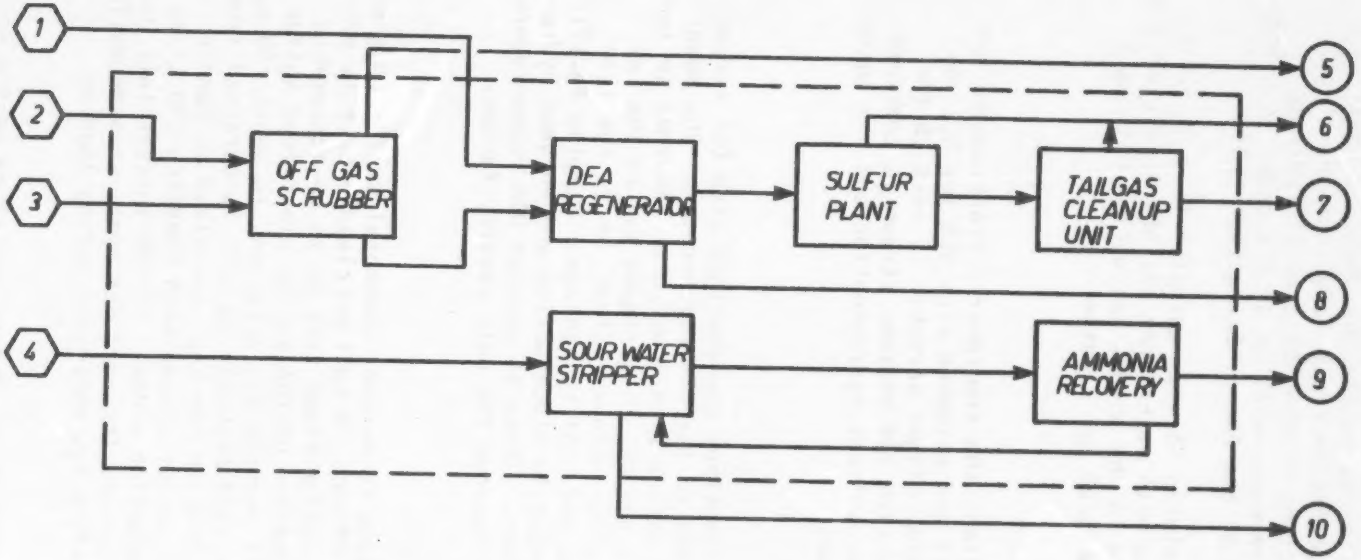
- Ammonia Recovery

The NH_3/H_2O vapor from the sour water stripper passes through a suction knockout drum and is compressed, cooled, and separated. The knockout liquid is recycled to the sour water treating facilities, while the vapor follows the same sequence through two more stages of compression. The essentially pure NH_3 vapor leaving the third stage of compression is condensed at 110°F to yield an anhydrous ammonia product of 99.8 percent purity.

The EDS plant contains 2-50 percent ammonia recovery trains, each integrated with one of the sour water treating trains. Each train is designed to recover 60 ST/SD from a single liquefaction train (120 ST/SD per plant).

- Phenolic Water Treating

The stripped sour water is cooled at 241°F and fed to the Phenol Extraction Unit. This unit is designed to extract the mixed phenols from the


1
2
3
4
OFF GAS SCRUBBER
DEA REGENERATOR
SULFUR PLANT
TAILGAS CLEANUP UNIT
SOUR WATER STRIPPER
AMMONIA RECOVERY
5
6
7
8
9
10

STREAM / CHARACTER	UNITS	1 RICH DEA	2 LEAN DEA	3 UNTREATED OFF GAS	4 SOUR WATER	⑤ TO HYDROGEN	⑥ SULFUR	⑦ VENT GAS	⑧ LEAN DEA	⑨ ANHYDROUS AMMONIA	⑩ TO PHENOL EXTRACTION UNIT
FLOW RATE	KLBS/HR.	1954*	896*		828.8		54.88		2850*	10.0	1103.0
STATE		LIQUID	LIQUID	GAS	LIQUID	GAS	SOLID	GAS	LIQUID	GAS	LIQUID
CONC. POLLUT.											
SOLIDS											
LIQUIDS											
GASES											
OTHER											

*GPM

** DATA HAS BEEN SUMMED OVER 2 TRAINS

FIG.2.2 SOUR GAS AND WATER TREATMENT PROCESSES: EDS PLANT

stripped sour water and from the slurry dryer phenolic water. The plant contains 2-50 percent phenol extraction units each sized to handle the phenolic water effluent rate of 1100 gpm from a single liquefaction train (2200 gpm pet plant). Preliminary results from pilot plant simulations of the EDS process indicate that the phenolic concentrations in the waste water will be of the order 3000-4000 wppm. Figure 23 is a simplified flow sheet of the Phenol Extraction Unit.

The effluent water (containing 18 wppm phenols) is sent to the offsite waste water equalization tank along with water from the API Separator (see Section 6.4.4). Crude phenols are recovered in the phenol extraction unit at a rate of 120 B/SD per liquefaction train (240 B/SD per plant).

- Gas Treating

In the gas treating section, the atmospheric fractionator and solvent stripper offgas streams are combined and scrubbed with DEA for H_2S removal. The overhead gas from the fractionator offgas scrubber is sent to the cryogenic hydrogen concentration unit. The rich DEA bottoms stream is combined with the rich DEA streams from liquefaction, solvent hydrogenation and the coker, and fed to the DEA hydrocarbon skimming drum.

- DEA Regeneration

In the DEA regeneration section, the combined rich DEA stream is preheated against lean DEA product and fed to the DEA regenerator. The tower overhead is partially condensed to yield a reflux stream which is returned to the tower and a vapor stream containing the H_2S and CO_2 is stripped out in the regenerator. The vapor stream is fed to a sulfur recovery plant, while the lean DEA bottoms from the regenerator are cooled and sent to tankage. Pumping facilities are provided to pump the lean DEA charges to liquefaction and solvent hydrogenation sections and to the offgas scrubbers. Three 50 percent DEA regenerators (two operating, one spare) are provided to improve the unit service factor.

- Sulfur Recovery

A sulfur plant is provided to recover elemental sulfur from the combined H_2S stripper and DEA regenerator offgas. A tail gas cleanup unit is provided to reduce the sulfur content of the sulfur plant tail gas to an acceptable environmental level. Approximately 99.9 percent of the sulfur plant feed sulfur is recovered while the tail gas cleanup unit reduces SO_2 emissions to about 100 ppm. The gas treating solution required for the tail gas clean up unit is obtained from the flexicoker H_2S removal unit regenerator which has been oversized to handle this additional service. Three-50 percent sulfur plants each handling 280 LT/SD of sulfur are provided for the total liquefaction plant. Two-50 percent tail gas cleanup units are also provided. Facilities are included for continuous degasification of the sulfur plant sulfur pits to reduce H_2S emissions during loading operations.

6.4.3.2 Sources of Emissions: The only source of gaseous emissions in the sour water and gas treatment processes are the stack gases from the tail gas cleanup unit.

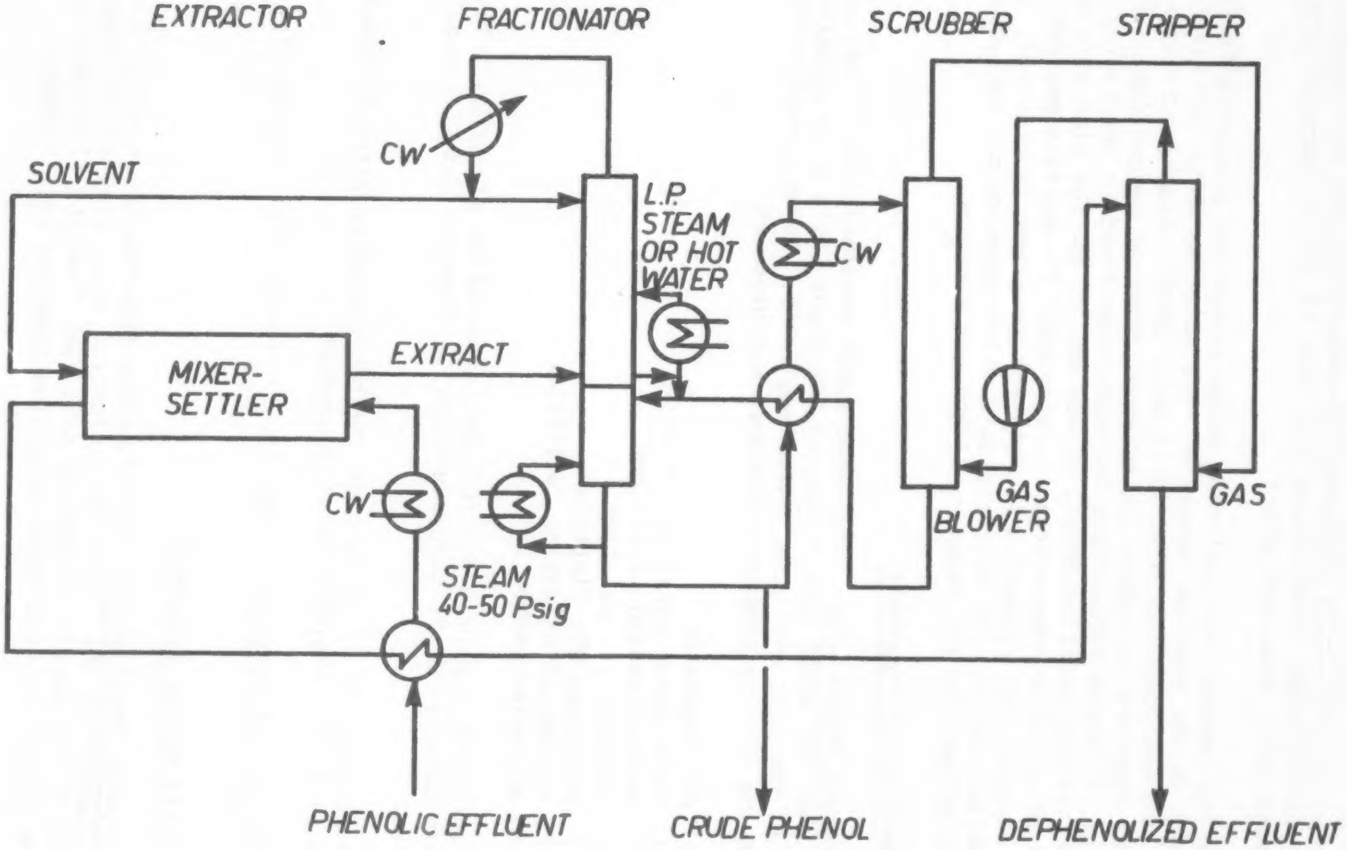

EXTRACTOR
FRACTIONATOR
SCRUBBER
STRIPPER
CW
SOLVENT
L.P. STEAM OR HOT WATER
CW
MIXER-SETTLER
EXTRACT
CW
STEAM 40-50 Psig
GAS BLOWER
GAS
PHENOLIC EFFLUENT
CRUDE PHENOL
DEPHENOLIZED EFFLUENT

FIG.2 3 PHENOL EXTRACTION FLOW PLAN: EDS PLANT

The approximate stack gas composition has been estimated to contain less than 100 ppm of SO_2. Further details are given in Table 10.

As far as the liquid effluents are concerned, the exit waters from the phenol extraction plant (containing less than 18 ppm of phenols) are sent to the offsite waste water treatment plant.

The H_2S removal unit solution purge stream may present some water treating problems due to the chemical nature of this solution which contains vanadium, thiosulfates, and anthraquinone disulfonic acid (ADA). Separate treatment of this solution may be required to reduce the effluent chemical oxygen demand (COD) due to thiosulfate. Although thiosulfate is readily oxidized in the biological treatment unit, the optimum reaction occurs at low pH. Since the biox unit must be operated at a pH of 7-9 to remove organic compounds, thiosulfate may not be readily removed. If separate H_2S removal unit solution treatment is required, this may be done via acidification with sulfuric acid which converts the sodium thiosulfate to sulfate and allows for the recovery of ADA and vanadium.

6.4.4 Waste Water Treatment

6.4.4.1 Process Description: The waste water treatment facilities were designed on the basis that the NPDES permit for the EDS plant would be predicated on the installation of the best available technology (BAT). Using a design flow of 7,000 GPM the following offsite treatment sequence was proposed:

i) API Separator
ii) waste water equalization tank
iii) neutralization facilities
iv) chemical flocculation
v) dissolved air flotation
vi) biological oxidation facilities
vii) activated carbon units.

Facilities are provided for the regeneration of carbon. The sludge disposal train consists of i) thickeners, ii) a digestor and iii) gravity belt filter presses.

Approximately 15 percent of the treated waste water is reused as cooling tower makeup with the remainder being discharged.

6.4.4.2 Sources of Emissions: The treated waste water characteristics are outlined in Table 11.

6.4.5 Solid Wastes Treatment

6.4.5.1 Process Description: Solid wastes from the EDS process include digested biological sludge from the biological oxidation unit, oily sludge from the API separator and dissolved air floatation unit, ash from the flexicoker and solids removed from the boiler feed water cold lime treating unit blowdown.

TABLE 10 SOURCES OF CONTINUOUS EMISSIONS FOR THE EDS PLANT (12)

Source of Emission[e]	SO_2 lb/hr (vppm)[d]	CO lb/hr (vppm)	NO_x lb/hr (vppm)[b]	Particulates lb/hr (vppm)
Liquefaction Slurry preheat furnaces[c] (1368 MBtu/hr)	598 (150)	34 (20)	192 (100)	13 (7)
Solvent Hydrogenation Feed Preheat Furnaces (183 MBtu/hr)	80 (150)	5 (20)	26 (100)	2 (7)
H_2 Plant Steam Reformer Furnaces (2004 MBtu/hr)	876 (150)	50 (20)	281 (100)	20 (7)
Offsite Steam Boilers (207 MBtu/hr)[d]	91 (150)	5 (20)	29 (100)	2 (7)
H_2 Plant Deaerators	-	<1 (6)	-	-
CO_2 Removal Regenerator Overhead Drum (7600) MPH CO_2)	-	6 (25)	-	-
Tail Gas Cleanup Unit	39 (100)	22 (130)	3 (15)	-
Sulfur Plant Incinerator:				
Fuel Gas Combustion	3 (115)	<1 (20)	1 (75)	1 (10)
Sulfur Pit Purge Gas Combustion	27 (1000)	-	-	-
Totals	1714	124	532	38

Notes:

a. The SO_2 emission rates shown in the Table are based upon all sulfur being combusted to form SO_2 and no SO_3. Actually about 2-10 mole % of the sulfur can be expected to form SO_3.

b. The NO_x emission is expected to be a 90/10 mole % mixture of NO/NO_2 as it enters the atmosphere. Most of the NO will eventually oxidize to form NO_2.

c. Heat fired.

d. The continuous emission rates shown for the offsite steam boilers are based upon the firing of low-BTU gas (LBG) as the base fuel. If insufficient LBG is available, the boilers will fire LSFO as required. The intermittent emission rates shown for the offsite steam boilers are based upon firing LSFO as the fuel. The steam boilers have been designed to fire either fuel. If the firing of LSFO in the steam boilers proves to be unacceptable from an SO_2 and NO_x emissions standpoint, C_3 LPG can be substituted as the supplementary fuel.

e. Hydrocarbon emissions from sources such as tankage, flaring, process and safety valve vents and equipment leakages (e.g., valves, flanges, pump seals) are not included in the total hydrocarbon emission rate. The quantity of these hydrocarbon releases and the frequency with which they might occur was not determined since this was beyond the scope of the work done in the Design Study. Total hydrocarbon emissions came to 2 lbs/hr (from the H_2 decant deaerators).

TABLE 11

EFFLUENT CONCENTRATIONS FROM THE EDS OFFSITE WASTE WATER TREATING FACILITIES (21)

Contaminants	Effluent Conc., ppm	Contaminant Rates
Oil	<5	<20 lb/hr
Phenols	<1	<4 lb/hr
Hydrogen sulfide	<1	<4 lb/hr
Ammonia	<10	<35 lb/hr
BOD	10	-
COD	50-100	-
Suspended solids	<10	<35 lb/hr
Dissolved solids	~3200	~135 ST/D
Biological sludge		8 ST/D

Notes

a) The plant is designed to accept a flow of 7000 GPM
b) The offsite wastewater treatment train consists of i) API Separator, ii) Equalization Unit, iii) Neutralization Unit, iv) Dissolved Air Flotation, v) Biological Oxidation, vi) Filtration, vii) Activated Carbon and viii) Sludge Treatment

Sludges from the waste water treating facilities (API & DAF units) are thickened and then concentrated in a gravity belt filter. The sludge is then loaded into trucks and disposed of in a land farming operation outside the plant limits. The digested biological sludge should not create any odor problems.

The ash removed from the flexicoker low-Btu product gas is slurried with water and pumped to an above-ground lagoon for disposal. This lagoon is located about 1/2 mile from the plant site and has about a 5 year capacity. The lagoon will eventually be covered and reclaimed. The blowdown from the cold lime treating unit is thickened and disposed of with the ash from the flexicoker.

6.4.5.2 Sources of Emissions: No information has been found on possible emissions in the solid wastes treatment process.

6.4.6 Catalyst Handling

6.4.6.1 Process Description: The catalyst disposal schedule is outlined on Table 12. Several disposal options exists i) burying or landfill, ii) in-situ or ex-situ regeneration followed by re-use, or iii) metals reclamation. As of yet no definite plan has been decided upon.

6.4.6.2 Sources of Emissions: No information is available on the possible sources of emissions caused by removal of the catalysts.

6.5 EDS PLANT CONTROL TECHNOLOGY

In section 6.4 mention has been made of the treatment and disposal of EDS process waste products-- here, this information is presented in a more concise fashion.

6.5.1 EDS Plant Air Emissions Control Technology

As of yet only skimpy information has been provided on how the air emissions caused by the EDS process will be controlled. In fact, the air emissions problem has only been addressed in three stages of the EDS process a) coal handling and preparation, b) reactions and primary separations and, c) sour water and gas treatment.

The following steps will be undertaken to minimize emissions in the coal handling and preparation area:

1) Water sprays are provided at the track hopper pit to suppress the dusting resulting from bottom-dumping of coal from railroad cars.

2) Water sprays are also utilized at the outlets of the coal crushers.

3) The inclined conveyor belts from the crushers to feed the distributing bins are housed in a completely enclosed gallery with emissions controlled by baghouse filters.

TABLE 12

CATALYST DISPOSAL SCHEDULE: EDS PROCESS (21)

Location of Catalyst	Disposal Freq.	Amt. (ST)
Solvent hydrogenation reactors[(a)]		
H_2 plant hydrotreaters	Once every 4 years	95
H_2 plant zinc oxide reactors	Once every 2 years	240
H_2 plant steam reformers	Once every 4 years	150
H_2 plant high temperature shift reactors	Once every 2 years	160
H_2 plant low temperature shift reactors	Once every 2 years	300
H_2 plant methanator reactors	Once every 4 years	140
H_2 plant carbon treater-activated carbon	Once every 3 months	8
Sulfur plant convertors	Once every 2 years	180
Tail gas cleanup hydrogenation reactors	Once every 2 years	24

(a) The catalyst for solvent hydrogenation will be returned to the manufacturer for regeneration.

4) Each transfer point along the covered conveyor belts also has a baghouse filter to remove particulates and dust.

At this time, emissions in the coal handling and preparation area have not been quantified nor have the designs or the costs of the associated pollution equipment been detailed explicity.

The dry fines from the flexicoker are pneumatically conveyed to offsite mixing tanks. These dry fines are removed in a venturi scrubber prior to releasing the carrier air to the atmosphere. A very small but undetermined amount of dry fines is emitted to the atmosphere along with this air. An H_2S removal unit removed H_2S from the low-Btu fuel gas from the flexicoker. These items have been costed (see Table 13).

A scheme was presented for removal of hydrogen sulfide from the sour gas and sour water streams (see Section 6.4.3.1). Cost and ancillary data has been presented on the processing of hydrogen sulfide rich streams in the Claus and tail gas cleanup plants.

6.5.2 EDS Liquid Effluents Control Technology

Descriptions of the on-site and offsite liquid effluents control technology have been given in Sections 6.4.3.1 and 6.4.4.1.

The expected effluent characteristics from the waste water treatment plant are detailed in Table 11. Cost data is provided in Table 13.

6.5.3 EDS Solid Effluents Control Technology

As of yet very limited information is available on the control of solid wastes generated by the EDS process. The information at hand appears in Sections 6.4.5.1 and 6.4.6.1.

TABLE 13

COST OF POLLUTION CONTROL EQUIPMENT FOR THE EDS PROCESS (22)

Direct Material & Labor Costs (a)	M$ (b)	
o On-site		
Sulfur plant	9.8	
Tail gascleanup	3.9	
H_2S removal unit	13.0	
Sour water treating	7.4	
Ammonia recovery	1.8	
DEA regeneration	5.3	
Phenol extraction	7.5	
DEA scrubbing	2.0	
Total on site pollution abatement cost		50.7
o Offsite		
Waste water treating - BIOX	4.2	
- Act. C Treat.	7.9	
- Other	7.1	
Ash handling	9.7	
Sludge disposal	2.5	
Offsite tankage loading		
(S, NH_3, phenol, sour water)	3.5	
Cooling water facilities	4.0	
Total offsite pollution abatement cost		38.9
o Total direct pollution abatement cost		89.6

Notes:

(a) Excludes indirect charges and process and project contingencies
(b) M=million

Section 7

ALTERNATIVE CONTROL TECHNOLOGY SYSTEMS

7.1 INTRODUCTION

It has been apparent that close similarities exist between the H-Coal and EDS processes. In both cases the starting material is the same and the processing steps involved are also similar to a large extent. This includes coal handling, slurry preparation, primary reactors and separators, and product treatment. While the similarities are obvious, there are large gaps in the information actually available on these various unit process steps. At least for purposes of this study, the Applied Research Division of Dynalectron was able to obtain considerably more substantive information on the H-Coal process than on the EDS process. Therefore, it is decided to address the alternative control technologies of both these coal liquefaction processes in a unified manner. For instance, control technology and alternatives for tail gas cleanup will be treated as essentially the same in both cases; and similarly, the waste water treatment will be treated as a single type of process. This is considered appropriate because both liquefaction processes are similar and produce similar effluents. However, where there are significant variations and/or differences these will be dealt with separately and as specialized features.

The following multimedia emissions from a coal liquefaction plant can be identified:

1. Gaseous effluents:
   a. Tail gases from Claus furnaces containing sulfur compounds.
   b. Hydrocarbon emissions from vents.
   c. Combustion products from direct fired equipment and flares.
2. Liquid effluents
   a. Waste waters from process, cooling towers, boiler blowdown, coal pile runoff and pump seals.
   b. Hydrocarbons and solvents from leaks, spills and accidental discharges.
   c. Liquid wastes from hydrogen manufacture and oxygen plants.

3. Solid effluents

   a. Particulates from coal handling.
   b. Solids from deashing steps and hydrogen plant (if use is made of some of the coal residues other than vacuum tower bottoms).
   c. Spent catalysts, sludges and other process residues.

7.2 TAIL GAS TREATMENT

The basic Claus process usually employed for desulfurizing H_2S-rich gases (around 80 percent H_2S) can be designed and made to operate at a recovery efficiency of about 95 percent. The raw gas can sustain the combustion according to the reaction

$$H_2S + 1/2\ O_2 \longrightarrow S = H_2 + 2225\ \text{Btu/lb of } H_2S$$

Under these conditions, already present in the furnace, almost half of the hydrogen sulfide is converted to sulfur without any catalyst. The heat of reaction is recovered as high pressure steam and the sulfur produced is recovered as liquid by cooling down the gases to 300 - 350°F. The gases are then passed through a catalyst converter, where the reaction between the H_2S residue from the furnace and the SO_2 produced in the furnace takes place according to:

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O + 660\ \text{Btu/lb of } H_2S$$

The heat produced can be recovered as low pressure steam and one or more converters may be needed to drive the reactions to equilibrium. Sulfur is recovered again as liquid by cooling down the gases to about 300°F.

The tail gas from a Claus plant contains thus H_2S and SO_2 and some other sulfur compounds such as COS, CS_2 depending upon the feed composition. The amounts of these sulfur compounds is usually larger than that allowed by the present air pollution regulations. In order to meet these standards, the tail gases require cleanup. A scheme generally employed is to mix the tail gas with a hydrocarbon fuel and just enough air to maintain a reducing atmosphere and pass the mixture through a furnace. The SO_2 in the tail gas is reduced to H_2S increasing the H_2S concentration. This mixture is then sent to an amine recovery unit (absorber-stripper system) separating the H_2S tail gas. The H_2S is recycled to the front end of the plant and the clean tail gas goes to the stack via an incinerator if so required. A schematic of this system is shown in Figure 24. The H_2S concentration can be reduced to less than 100 ppm in a scheme like this. There are, however, other alternatives to this reduction, recovery and recycle (3R) sequence of tail gas cleanup. Some of these are described in the following subsections.

7.2.1 Institut Français du Pétrole (IFP) Process

A schematic of this process is shown in Figure 25. The process is based on liquid phase reaction between SO_2 and H_2S according to:

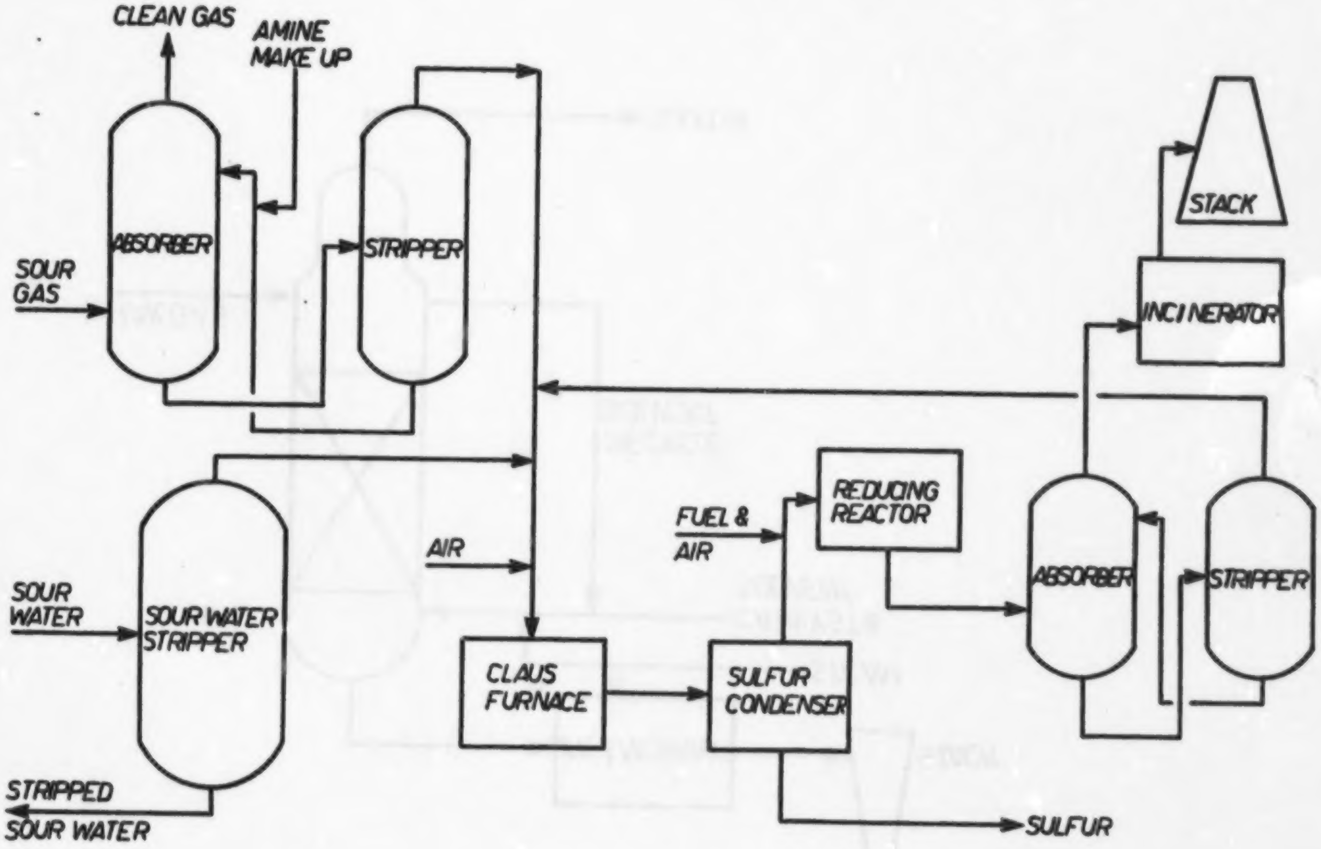

CLEAN GAS
AMINE MAKE UP
SOUR GAS
ABSORBER
STRIPPER
SOUR WATER
SOUR WATER STRIPPER
STRIPPED SOUR WATER
AIR
CLAUS FURNACE
SULFUR CONDENSER
FUEL & AIR
REDUCING REACTOR
SULFUR
ABSORBER
STRIPPER
INCINERATOR
STACK

FIG. 24 CONVENTIONAL DESULFURIZATION VIA AMINE/CLAUS SYSTEM WITH TAILGAS TREATMENT

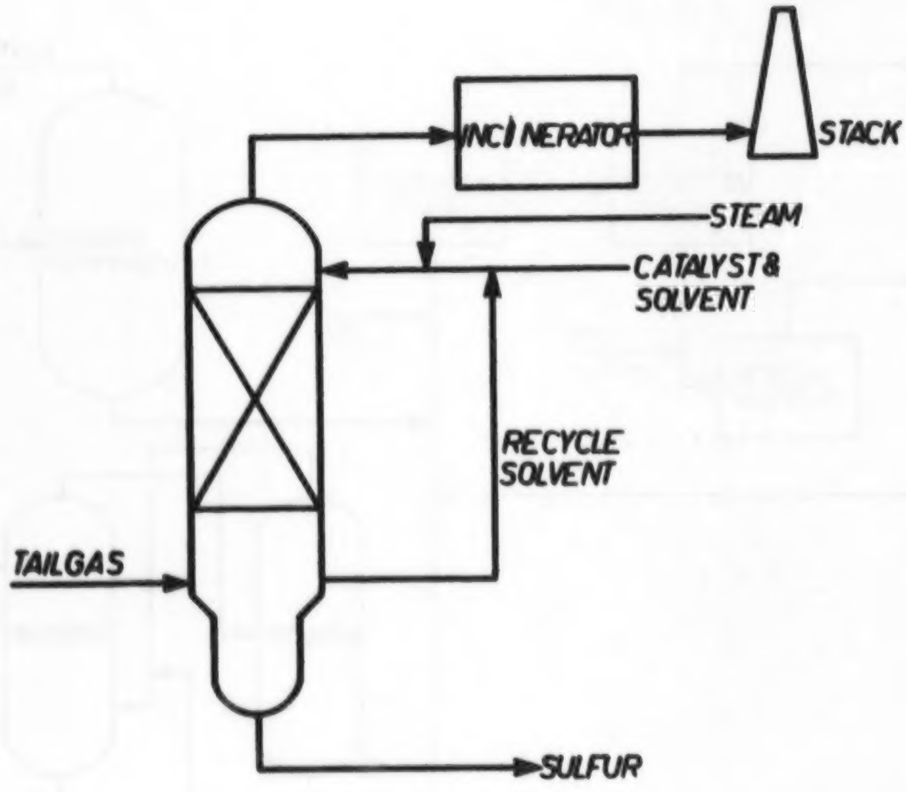

INCINERATOR
STACK
STEAM
CATALYST &
SOLVENT
RECYCLE
SOLVENT
TAILGAS
SULFUR

FIG. 25 IFP PROCESS SCHEMATIC

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O$$

The reaction is carried out in a solvent which dissolves both H_2S and SO_2. A catalyst is used to enhance the reaction rate. The equipment consists of a packed tower for gas-liquid contacting. The sulfur produced is insoluble in the solvent and forms tiny spheres which travel down the column along with the solvent. COS and CS_2 do not react and pass through the system. An incinerator can be used to destroy these and any residual H_2S that has not reacted.

The system is sensitive to H_2S/SO_2 ratio and so very close control of the feed composition is necessary. Attached to a Claus plant, the combined sulfur removal efficiency is about 99.3 percent.

7.2.2 Holmes-Stretford Process

This process is based on a complex chemistry of reduction of sodium and vanadium salts selectively by H_2S, producing sulfur in a aqueous medium. The salts are regenerated by means of air blown oxidation. The chemistry approximately is:

$$2V^{5+} + HS^- \longrightarrow 2V^{4+} + S + H^+$$
$$2V^{4+} + \text{ADA (oxidized)} \longrightarrow 2V^{5+} + \text{ADA (reduced)}$$

ADA (anthroquinone-disulfonic acid) is used only to provide a mechanism for accelerated oxidation of vanadium. The air converts the reduced vanadium into vanadate and also acts as a flotation agent to froth out the product sulfur. The process has an advantage in that it can be designed to desulfurize gases containing high concentrations of CO_2.

The process is proven technology and claims removal efficiencies of 99.5 percent and above with exit concentrations of H_2S of less than 50 ppm.

7.2.3 Beavon Process

The Beavon desulfurization system is based on a two-step operation. First the sulfur compounds in the Claus tail gas are reduced to H_2S in a catalytic reactor and as a second step the H_2S is removed using Stretford technology. Thus the process is simply a mix of reduction steps of the conventional tail gas treatment and Stretford process to remove H_2S instead of recycling it back to the Claus units. A schematic of the process is shown in Figure 26.

7.2.4 Lime/Limestone Scrubbing

As a throw away process in contrast to the regenerable processes described above this lime/limestone scrubbing system offers a powerful alternative because of its simplicity. The technology is well established in coal burning installations and the chemistry involved is simple. The process consists of incinerating the tail gases to convert all sulfur compounds to SO_2/SO_3 and absorb the SO_2/SO_3

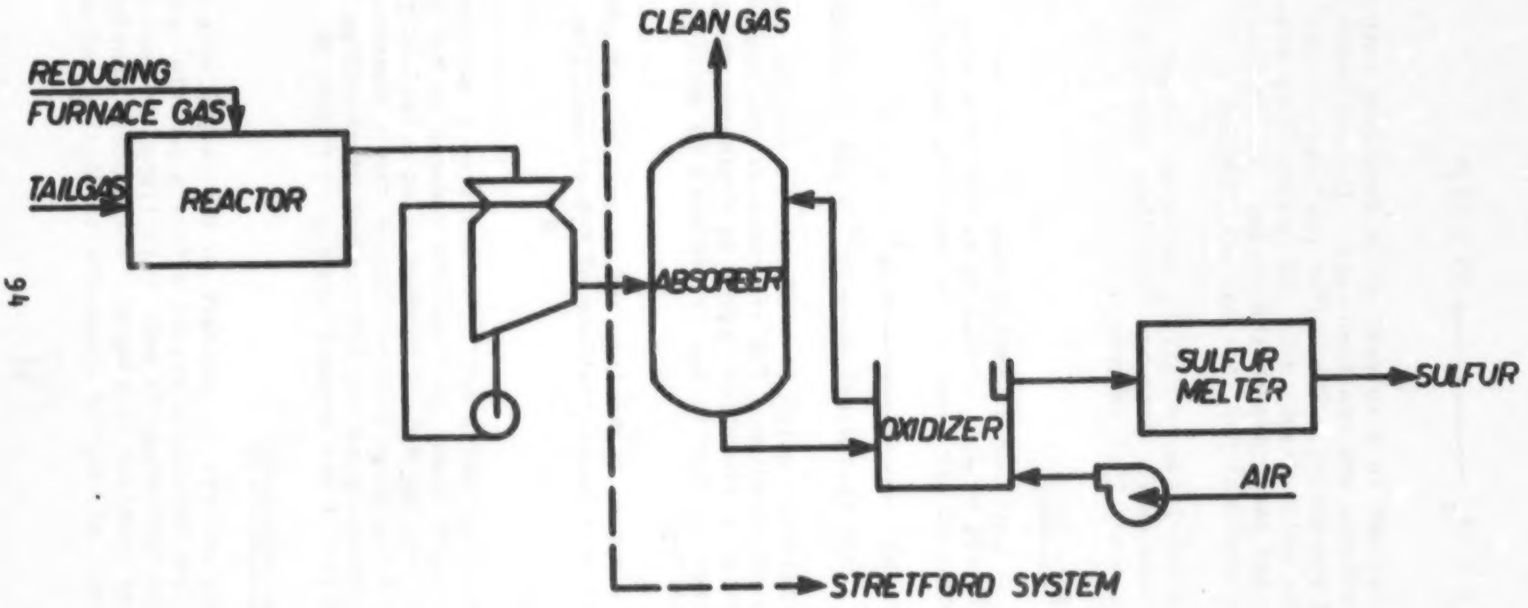

CLEAN GAS
REDUCING
FURNACE GAS
TAILGAS
REACTOR
ABSORBER
OXIDIZER
SULFUR
MELTER
SULFUR
AIR
STRETFORD SYSTEM

FIG. 26 BEAVON PROCESS SCHEMATIC

in a lime/limestone slurry producing calcium sulfite and sulfates which are discarded as fill material. A process schematic is shown in Figure 27.

7.2.5 Sulfox (UOP) Process

Essentially this process presents an alternative not only for tail gas treatment, but also to the Claus process itself. According to the claims by its developer--the Process Division of UOP-- the Sulfox process can process both sour water and sour gas together to 10-100 ppm of objectionable pollutants. The process is schematically represented in Figure 28.

Sour refinery gas is introduced into an absorber, where it is scrubbed with aqueous ammonia solution. The rich liquor from the bottom of the absorber is mixed with sour water, heated, aerated and passed through two oxidizing reactors. The reactions involved are:

$$NH_4HS + 1/2\ O_2 \longrightarrow S + H_2O + NH_3$$

$$NH_4HS + nS \longrightarrow NH_4S_nHS$$

Waste gas consisting primarily of nitrogen (the oxygen has been used up in the reactors) is separated and sent to a scrubber where ammonia is scrubbed out by water. The sulfur is removed from the bottom of the second reactor. The liquor is essentailly aqueous ammonia and is recycled to the absorber.

While the claimed removal efficiencies are very high, the process remains still untried on a large scale. However, since the sour water from coal liquefaction contains both hydroden sulfide and ammonia, the process may have a great promise of efficacy.

7.2.6 Systems Analysis

All tail tas treatment systems can be studied in a unified manner by means of a systems analysis. The total system consists of three subsystems as shown in Figure 29: first the Claus system, followed by a tail gas treatment, which is then followed by product disposal.

The conventional (or commonly used) sequence is for the tail gas to be reduced and then the amine scrubbed to remove the H_2S, which is then recycled. Several variations of this process scheme are known and available.

Another alternative is to incinerate the tail gases to convert all the sulfur compounds to SO_2 and desulfurize the flue gas by any one of the know Flue Gas Desulfurization (FGD) technologies.

The third group of alternatives is to react the tail gas catalytically and produce elemental sulfur like the IFP, Sulfreeen, and SNPA processes. These are sensitive to feed composition processes. Since coal liquefaction tail gases very widely in their compositions depending on the type of coal used, this group of alternatives may not be the most suitable as control technology elements of fuel

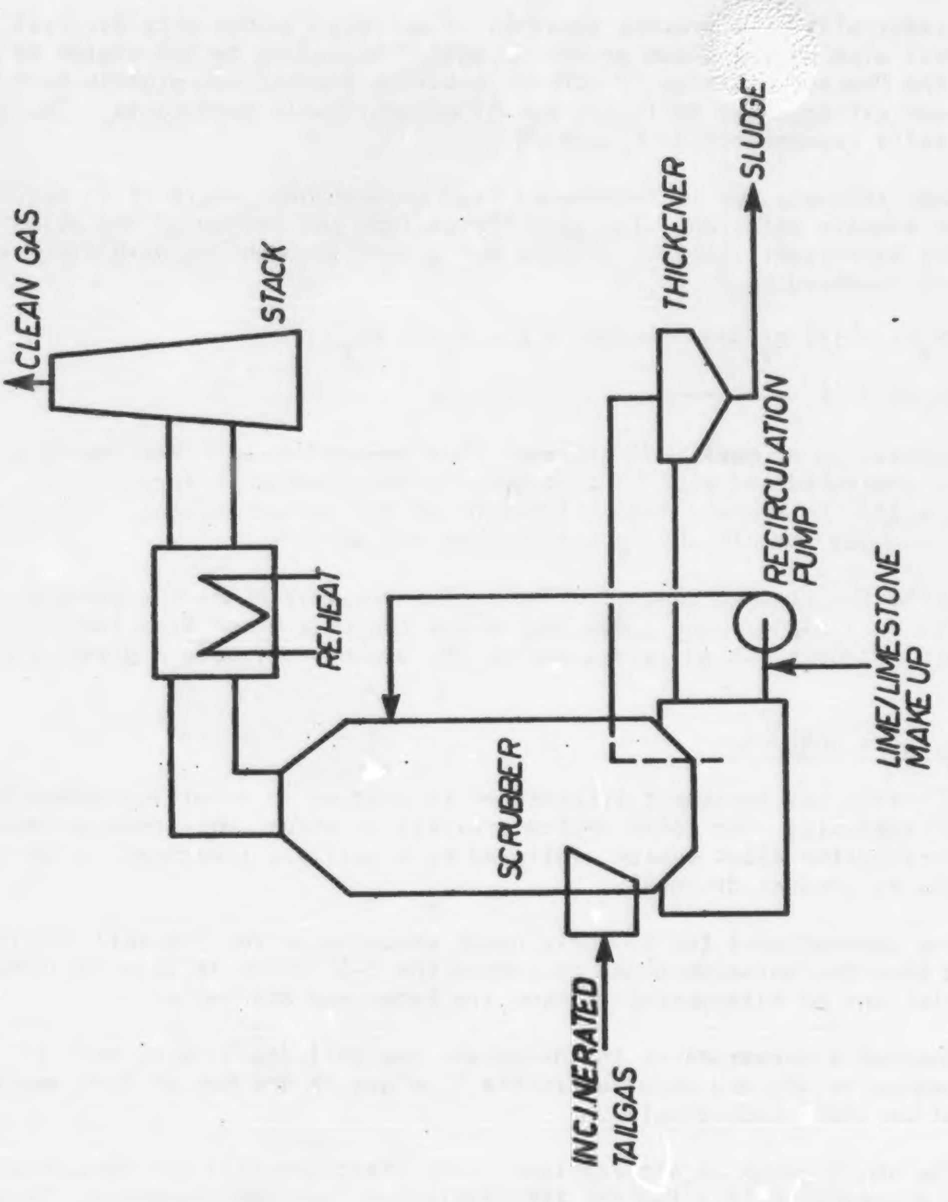
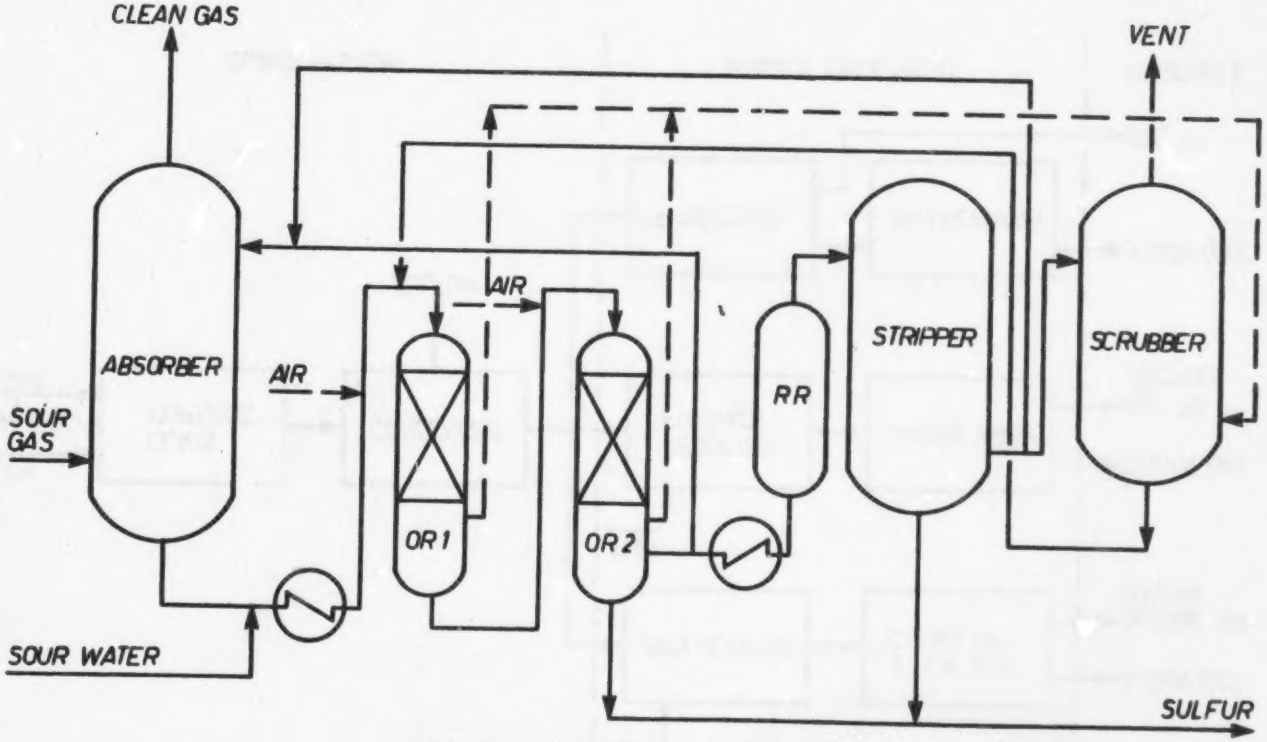

CLEAN GAS
STACK
REHEAT
THICKENER
SLUDGE
RECIRCULATION PUMP
LIME/LIMESTONE MAKE UP
SCRUBBER
INCINERATED TAILGAS

FIG. 27 SCHEMATIC OF LIME/LIMESTONE SCRUBBING SYSTEM


CLEAN GAS
VENT
ABSORBER
SOUR GAS
AIR
AIR
OR 1
OR 2
RR
STRIPPER
SCRUBBER
SOUR WATER
SULFUR

OR 1, OR 2: OXIDATION REACTORS
RR: REDUCTION REACTOR

FIG. 28 SULFOX (UOP) PROCESS (DOES NOT REQUIRE CLAUS UNITS)

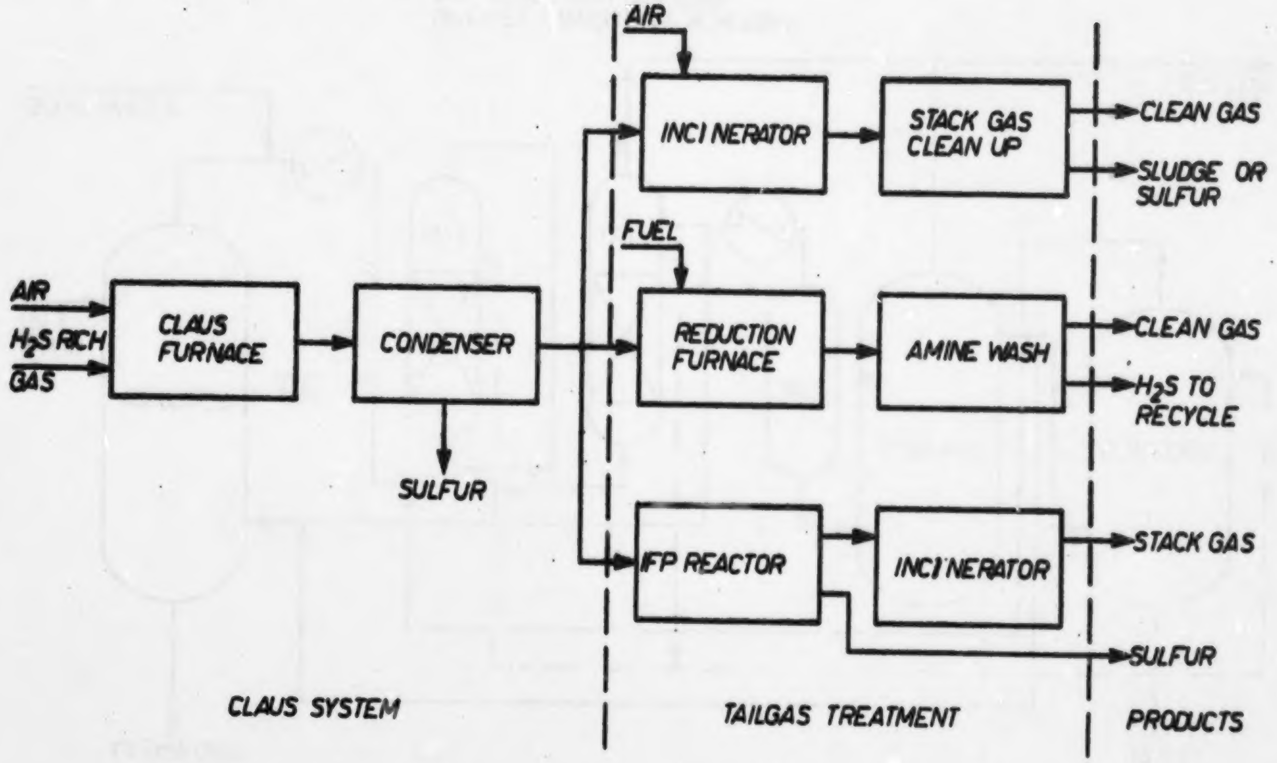

AIR
H2S RICH
GAS
CLAUS FURNACE
CONDENSER
SULFUR
AIR
INCINERATOR
STACK GAS CLEAN UP
CLEAN GAS
SLUDGE OR SULFUR
FUEL
REDUCTION FURNACE
AMINE WASH
CLEAN GAS
H2S TO RECYCLE
IFP REACTOR
INCINERATOR
STACK GAS
SULFUR
CLAUS SYSTEM
TAILGAS TREATMENT
PRODUCTS

FIG. 29 GAS TREATMENT PROCESS ALTERNATIVES SCHEMATIC

converter outputs.

7.3 HYDROCARBON EMISSIONS

The principal sources of hydrocarbon emissions are: 1.) vents, 2.) safety devices like rupture discs, valves, etc. to protect the equipment from runaway operation, and 3.) spills, accidents and rupture lines. In all of these cases, the control technology to deal with these eventualities is strictly a matter of mechanical design and providing suitable safeguards. There are codes for these purposes, such as the ASME codes for pressure vessel and piping design, ASCE codes for structural design and strict adherence to OSHA standards.

7.4 COMBUSTION PRODUCTS

The origin of these emissions is mainly the power plant to support the liquefaction plant. Control technology of fluegas treatment consists at the present time of SO_x control and particulates. Both are more or less well established technologies and the alternatives are dictated by state and local regulations.

Other sources of combustion products are direct fired heaters and flares. There is little of importance as far as control technology of these emissions is concerned.

7.5 LIQUID EFFLUENTS

7.5.1 Relevant Statutes and Regulations Governing the Disposal of Liquid Effluents

In recent times in the economically developed countries, industrial development has been tempered by the need to maintain and enhance the quality of the environment. In the United States this attitude is reflected in the goal that has been set for the complete elimination of industrial point-source liquid effluents by 1985. The pathway toward meeting this goal has been delineated in two statutes and their concomitant regulations, namely the Federal Water Review Pollution Control Act as amended in 1972 and the Clean Water Act of 1977.

Pollutants have been identified as "conventional" (such as BOD or suspended solids (SS)), "toxic" (according to a list of 65 elements, compounds or families of compounds) or "non-conventional" (pollutants other than conventional or toxic). By the time commercial size coal liquefaction plants will be in operation (from the middle to the end of the next decade) the following EPA promulgated industrial liquid effluent standards will be in force:

a) For toxic pollutants, effluent standards will be based on the "best available technology" (BAT).

b) For conventional pollutants, effluent standards will be based on the best "conventional pollution control technology" (BPCT). This level of technology can be no less than "best practicable control technology" (BPT) and as high as BAT.

c) For non-conventional pollutants industry must comply with BAT.

The treatment of wastewaters to meet the above mentioned point source standards oftentimes produces sludges containing various levels of toxic pollutants. These types of sludges are defined as hazardous wastes under Section 3001 of the Resource Conservation and Recovery Act (RCRA) of 1976 and will be subject to recently promulgated EPA regulations that govern the treatment, generation, transportation, storage and disposal of hazardous wastes.

The above discussion has been limited to the impact of federal statutes. At the state level, there is always the possibility that more stringent statutes and regulations may govern the disposal of liquid effluents (and their concomitant sludges). In general, however, the states have decided to follow the federal laws and regulations. Also, since the locations of the commercial size coal liquefaction plants (for both the H-Coal and the EDS processes) have not yet been decided on, the following dicussion will take as its starting point the federal regulations only.

7.5.2 Water Management Program

The principal wastewater sources for a typical coal liquefaction plant have been delineated in Figure 22. In quantity the major source of wastewater pollution is the non-contact water (including blowdown) used for evaporative cooling systems (11). Other major sources of wastewater are also extra-process produced such as drawoff from tankage and excess collected condensate and the runoff from various process areas such as the tankage area, and the coal preparation area.

The federal regulations that will be in force by 1985 will have the effect of mandating not only a reduction in the amount of the pollutants discharged, but also a reduction in the amount of water discharged. To achieve substantial reductions in the amounts of waste discharged, a very thorough water management program will have to be implemented and will include i) those innovations that will reduce extra-process water needs such as cooling systems or combined air/water cooling systems, ii) a comprehensive re-cycle/re-use program, iii) a very detailed housekeeping program.

Other aspects of a water management program that will affect the character of wastewaters that will be treated at the wastewater treatment plant are i) incorporation of phenol sulfur and ammonia recovery units, ii) segregation of incompatible streams.

The water management program as such will not be referred to again in this report as all in-plant activities fall outside its scope. A good starting point for such information is reference (23). The remainder of this discussion will look at the "end of pipe" (offsite) wastewater treatment system alternatives from both technological and cost viewpoints.

7.5.3 Offsite Wastewater Treatment Alternatives

As of yet, no point source effluent standards for coal liquefaction processes have been promulgated mainly because these processes have not yet passed the fledgling state--the largest coal liquefaction plant currently operating is the DOE-financed pilot plant at Tacoma, Washington. This plant incorporates the SRC-II process and has a coal utilization rate of 45 metric tons per day. However, comprehensive regulations have been promulgated for a similar industry, namely the petroleum refining industry.

Further discussion will be based on the premise that when point source effluent discharge regulations will be promulgated they will be very similar in nature to those in effect for the petroleum refining industry. The fact that the organic wastewater pollutants for coal conversion processes tend to be aromatic in nature while the petroleum refinery wastewaters tend to be aliphatic will be taken into account.

The standards that will be in force will, at a minimum, demand that the effluents be treated to the tertiary level. A wide variety of pre-treatment, suspended solids removal, secondary treatment, and tertiary treatment options plus liquid and sludge disposal possibilities are outlined in Figure 30. All the technology up to and including secondary treatment has been demonstrated amply to the commercial plant level. However, except for chlorination and activated carbon, most tertiary treatment processes have not been tested at the commercial plant level. It is expected that in the next decade all the mentioned tertiary processes will become proven technology.

It is possible that an additional level of treatment will be needed to ensure that the toxic effluent standards will be met. Treatment processes such as electrodialysis, electrolysis, alkaline chlorination, freeze crystalization and evaporation will have to be considered. Of particular concern is the likely presence of heavy metals in the wastewater due to their presence in the coal raw materials. Antimony, arsenic, beryllium, chromium, copper, lead, mercury, and nickel are typically found in coal, as shown in Table 14.

The options of sludge and ash disposal are likewise limited due to the presence of heavy metals in the sludge. The only feasible options are incineration, lagooning, sanitary landfill and chemfixing.

The offsite wastewater treatment and sludge disposal scheme proposed for the EDS process corresponds to a tertiary treatment plant. The wastewater treatment process proposed for the H-Coal plant at Catlettsburg, Kentucky separates incompatible waste streams and treats them to the secondary level before their final disposal in the rivers.

7.6 SOLID WASTES

The bulk of the solid waste of an integrated coal liquefaction plant comes from the ash and mineral content of the coal. The point where it emanates from the plant depends upon the design of the plant. In H-Coal plants this is at the gasifier for hydrogen the production unit. As mentioned before in Section 5.5.3, the method of disposal of this solid waste envisaged at the present time

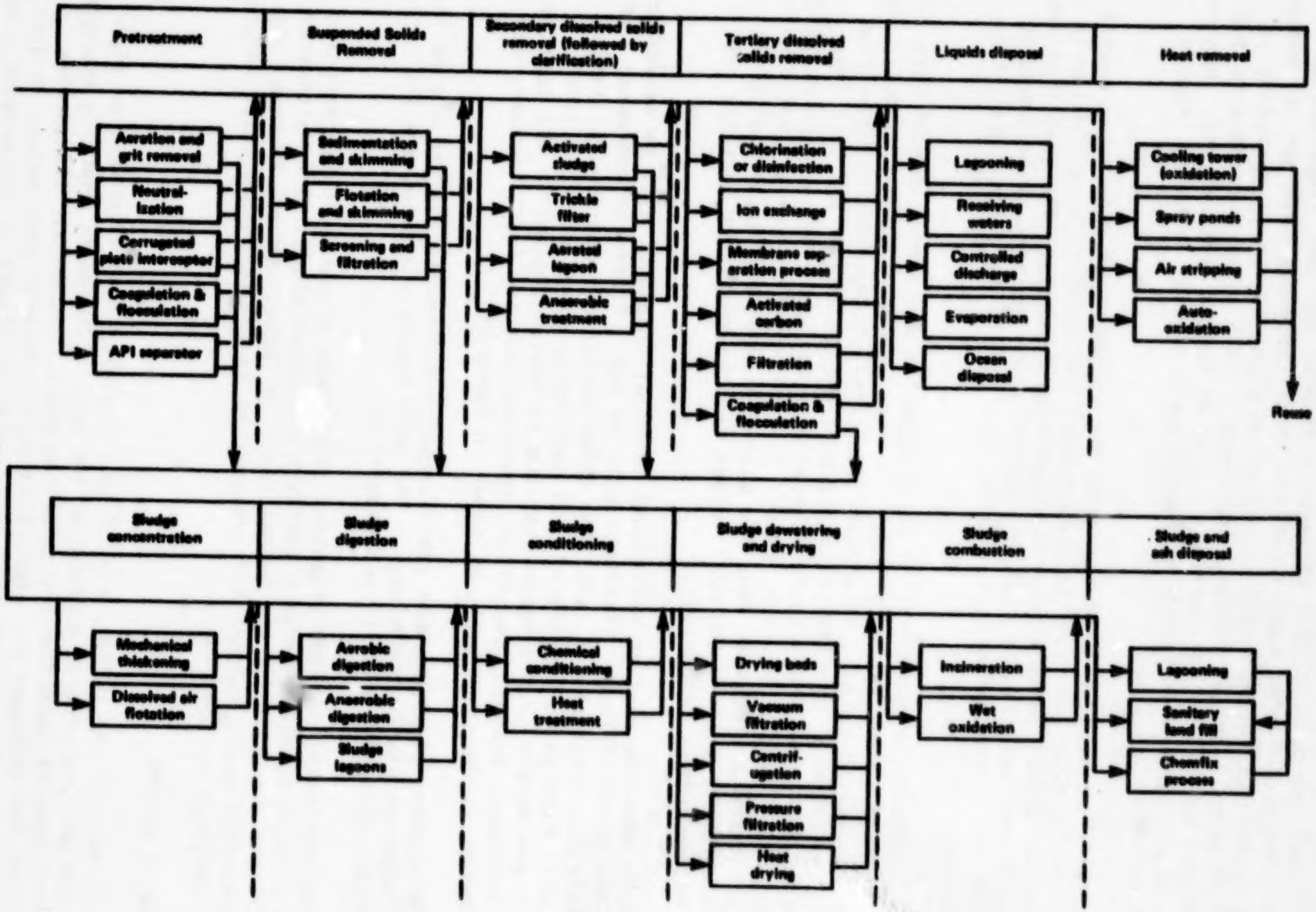

Pretreatment
Suspended Solids Removal
Secondary dissolved solids removal (followed by clarification)
Tertiary dissolved solids removal
Liquids disposal
Heat removal
Aeration and grit removal
Neutral-ization
Corrugated plate interceptor
Coagulation & flocculation
API separator
Sedimentation and skimming
Flotation and skimming
Screening and filtration
Activated sludge
Trickle filter
Aerated lagoon
Anaerobic treatment
Chlorination or disinfection
Ion exchange
Membrane sep-aration process
Activated carbon
Filtration
Coagulation & flocculation
Lagooning
Receiving waters
Controlled discharge
Evaporation
Ocean disposal
Cooling tower (oxidation)
Spray ponds
Air stripping
Auto-oxidation
Reuse
Sludge concentration
Sludge digestion
Sludge conditioning
Sludge dewatering and drying
Sludge combustion
Sludge and ash disposal
Mechanical thickening
Dissolved air flotation
Aerobic digestion
Anaerobic digestion
Sludge lagoons
Chemical conditioning
Heat treatment
Drying beds
Vacuum filtration
Centrif-ugation
Pressure filtration
Heat drying
Incineration
Wet oxidation
Lagooning
Sanitary land fill
Chemfix process

FIG. 30 WASTEWATER PROCESSING ALTERNATIVES FOR A COMMERCIAL COAL LIQUEFACTION PROCESS

TABLE 14

TRACE ELEMENT COMPOSITION OF ILLINOIS NO. 6 COAL SAMPLES (24)

Element	ppm	Element	ppm
Aluminum	13500	Rubidium	16
Antimony	0.98	Samarium	1.2
Arsenic	5.9	Scandium	2.6
Barium	111	Selenium	2.2
Berryllium	1.5	Silicon	26800
Boron	135	Silver	0.03
Bromine	15	Sodium	660
Cadmium	<4	Strontium	36
Calcium	7690	Tantalum	0.16
Cerium	13	Terbium	0.17
Cesium	1.2	Thallium	0.67
Chlorine	1600	Thorium	2.2
Chromium	20	Tin	4.7
Cobalt	6.6	Titanium	700
Copper	13	Tungsten	0.7
Dysprosium	1.0	Uranium	1.6
Europium	0.25	Vanadium	33
Fluorine	63	Ytterbium	0.54
Gallium	3.1	Zinc	420
Germanium	<5.6	Zirconium	52
Hafnium	0.52		
Indium	0.14		
Iodine	1.9		
Iron	18600		
Lanthanum	7		
Lead	27		
Lutetium	0.08		
Magnesium	510		
Manganese	53		
Mercury	0.18		
Molybdenum	9.2		
Nickel	22		
Phosphorus	45		
Potassium	1700		

is as fill material. The technology of landfilling is well known from power plants and other landfill projects.

Since, in the case of the H-Coal process, the solid waste material comes out from the gasifier in the form of fused slag or glassy material, this suggests possible alternatives for its use as building material.

Another effluent in solid form is the particulate emission from coal handling. This can be controlled effectively by wet scrubbing and recycling the sludge either to the reactors or to the gasifier. This method of dust supression should prove not only effective, but economical in the long run because of low maintenance costs and less frequent shut downs.

Wastewater treatment also produces sludges which have to be disposed of after dewatering. Usually, sludges are disposed as soil spread, making available the nutrients in them for plants and vegetation. However, in this case the procedure is not suitable because of the trace metals contained in this sludge. So the only method of disposal of this sludge is as landfill along with other solid wastes.

SECTION 8

COST EVALUATION

8.1 INTRODUCTION

Implementation of new and untested environmental control technology is a matter of vital concern to both the concerned public as well as to the branch of government charged with the mandate of insuring the quality of our environment, in this case the U.S. Environmental Protection Agency. Therefore, it is only logical to ask some pointed questions such as whether the control technology is usable and does it represent the minimum economic penalty for meeting environmental goals. These are, naturally, very involved questions even in those cases where the technology is well know and tested. In case of coal liquefaction where the process technology is still emerging, it is very difficult to assess the control technology according to the above criteria.

In the following, an attempt will be made to evaluate the costs of the control technology. It should be pointed out that these are only approximate numbers based on plants in similar industries and on professional experience. Their accuracy is believed to be within ± 20 percent.

8.1.1 Methodology of Approach

The methodology for cost assessment is as follows: First, the capital cost of a base case control technology will be estimated. This is to be done for all effluents i.e., gases, liquids and solids. Then the approximate operating costs will be estimated for all three classes of effluents. The total cost of control technology is then calculated using suitable rates for depreciation and return on investment for the life of the system. From this, total cost, the share of control technology cost as dollars per barrel of LFE (liquid fuel equivalent) is evaluated. This is the base case cost of control technology of a coal liquefaction plant, and can be expressed as

$$S_{ct} = S_g + S_l + S_s + S_c \qquad \text{(Equation 1)}$$

where S_{ct} = total cost of control technology
S_g, S_l, S_s, S_c = parts constituting gas treatment, liquid treatment, solid treatment and capital related.

For alternative technologies, depending upon which alternative is being considered, it can be evaluated as

$$\Delta_1 = {}_1S_g + S_l + S_s + S_c$$

$$\text{or} \quad \Delta_2 = S_g + {}_2S_l + S_s + S_c \qquad \text{(Equation 2)}$$

$$\text{or} \quad \Delta_3 = S_g + S_l + {}_3S_s + S_c$$

The variance of control technology cost is then calculated as

$$E_n = \frac{\Delta_n}{S_{ct}} \qquad \text{(Equation 3)}$$

8.2 COST OF CONTROL TECHNOLOGY

As mentioned in the preceding subsection, the cost of a base control technology system will be evaluated first. The base case is assumed as:

A. Gas Treatment Train Consisting of
   1. Reduction furnace
   2. Amine wash system
   3. H_2S stripper
   4. Solvent recovery
   5. Incinerator

B. Water Treatment Train consisting of
   1. API-separator
   2. Equalizer
   3. Pretreater
   4. Aeration units
   5. Biox units
   6. Filtration
   7. Activated carbon
   8. Sludge treatment

C. Solid Treatment consisting of
   1. Bag filters
   2. Slag cooler
   3. Size reducers
   4. Catalyst cleaning
   5. Loading and dispersing
   6. Fill spreaders

All costs of these units are estimated in 1978 dollars for a 25,000 tons of coal per day liquefaction plant.

8.2.1 Capital Costs

Unit	Cost (in million $)
Gas treatment train (GTT)	6.6
Buildings & structures	1.3
Total (GTT)	7.9
Water treatment train (WTT)	21.7
Solids Treatment	5.3
Buildings & structures	1.1
Total solids treatment	6.4
Total investment cost of CT	36.0

8.2.2 Operating Costs

Item	Cost/yr (in thousand $)	Life cycle cost (in million $)
Gas Treatment	954	19.0
Water Treatment	3250	65.0
Solid Treatment	996	20.0
Total	5200	140.0

8.2.3 Capital Related Costs

1. Depreciation calculated as straight line over 20 years	36.0
2. ROI calculated as straight 10 percent over 20 years	72.0

8.2.4 Control Technology Cost Share

Total cost of CT = 212×10^6 (dollars)

Total production = 3.55×10^{15} Btu = 5.92×10^8 Bbl (LFE)

$$S_{ct} = \frac{2.12 \times 10^8}{5.92 \times 10^8} = 0.35 \text{ (\$/Bbl)}$$

8.3 COST OF ALTERNATIVE TECHNOLOGIES

It is apparent from the nature of Equation 2 which formulates the incremental changes in the cost of control technology due to an alternative, that a very large number of Δ's and thus E's can exist. Any one or a combination of alternatives results in a separate Δ and so making it an eigen valued Δ. It is impractical to list all the possible variations, and so it was decided only to attempt two variations; one resulting in the lowest Δ and the other the highest Δ.

These constitute the lower and upper bounds of the share of the environmental cost. A quick evaluation shows the lowest case (or least expensive) alternative to be burning the tail gas and treating the SO_2-containing flue gas as a throwaway FGD system for the gas treatment train with a water treatment train and wet scrubber for particulates. The most expensive or upper bound is a regenerative treatment train for gases such as Beavon, with a waste water treatment system that removes all toxic materials above and beyond the capabilities of a tertiary treatment system. This would be coupled with a solid waste treatment system such as a lined and covered pond.

The changes in the control technology costs are, in the least expensive case, -46×10^6, and in the most expensive case, $+165 \times 10^6$, giving $E_{min} = 0.78$ and $E_{max} = 1.78$. The resultant variation in the control technology cost share is 0.273 \$/Bbl minimum and 0.623 \$/Bbl maximum.

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APPENDIX A

TABLE OF CONVERSION FACTORS TO SI UNITS

Multiply English Unit	by	To Obtain SI Unit
bbl (oil)	0.1590	m^3
Btu	1.056	J
Btu/lb	2.328	J/g
°F	(°F-32)x5/9	°C
ft	0.3048	m
ft^2	0.0929	m^2
ft^3	0.0283	m^3
gal	3.785×10^{-3}	
in	0.0254	m
lb	453.6	g
lb/10^6Btu	0.4295	g/MJ
mi	1609	m
psi	6895	Pa
ton	908	kg